Proposed Uniform Standards for Interconnecting Distributed Generation in Massachusetts

Submitted to:

MASSACHUSETTS DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY IN COMPLIANCE WITH DTE ORDER 02-38-A

by the

DISTRIBUTED GENERATION INTERCONNECTION COLLABORATIVE

MARCH 3, 2003

Mediated by Jonathan Raab, President, Raab Associates, Ltd.
and
Suzanne Orenstein

Technical Consulting From Navigant Consulting, Inc.

With Funding Provided by the Massachusetts Technology Collaborative

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Date: March 3, 2003

To: Department of Telecommunication and Energy
From: Dr. Jonathan Raab, Raab Associates, Ltd.

Re: Massachusetts Distributed Generation Collaborative Initiated by DTE Order 02-38-A

On behalf of the Massachusetts Distributed Generation ("DG") Collaborative, which was funded by the Massachusetts Technology Collaborative, please find attached the DG Collaborative's final report. The report describes a comprehensive starting point for DG interconnection in the Commonwealth covering all sizes of DG on both radial and secondary network systems. It includes a detailed process narrative, timeframes, a fee structure, an alternative dispute resolution (ADR) process, interconnection requirements, a mechanism for tracking interconnections experience over time, and an application form.

The Stakeholders have worked diligently to develop this comprehensive, inter-related package of approaches through the give-and-take of in-depth negotiations. In the context of negotiation and compromise, the Stakeholders fully endorse the report as a whole, acknowledging that it represents a reasonable starting place for interconnection standards. Changes to any portion of the report may lead stakeholders to review their positions on other portions or on the report as a whole. The following Stakeholder organizations endorse the report. The report represents a consensus on all issues except one.

<table>
<tr><td colspan="2"><u>Utility Cluster</u>
Boston Edison, Cambridge Electric Light, Commonwealth Electric (NSTAR Electric)
WMECO (Northeast Utilities)
MECo/Nantucket Electric (National Grid)
Fitchburg Gas & Electric (Unitil)
ISO-New England</td></tr>
<tr><td><u>Distributed Generation Cluster</u>
Aegis Energy Services
E-Cubed Company, LLC
Solar Energy Business Association, New England
Ingersoll-Rand
National Association of Energy Service Companies
Northeast Combined Heat and Power Initiative
Turbosteam
Northeast Energy and Commerce Association
Real Energy
United Technologies Corporation
Keyspan
Conservation Services Group</td><td><u>Other Stakeholders</u>
MA Division of Energy Resources
Massachusetts Technology Collaborative*
Cape Light Compact
Associated Industries of Massachusetts
Wyeth Bio Pharmaceutical
Union of Concerned Scientists
MA Public Interest Research Group
Conservation Law Foundation
Massachusetts Energy Consumers Alliance
Northeast Energy Efficiency Council

*The director of the Massachusetts Renewable Energy Trust and the management of the MTC approve the report, subject to review by the MTC's board of directors.</td></tr>
</table>

The stakeholders request that the DTE act on their recommendations and issue an Interim Order specifying DG interconnection standards for the Commonwealth. The stakeholders do not intend to file separate comments on this subject prior to the DTE issuing its interim order or proposed rules.

The Stakeholders have agreed to continue the Collaborative with quarterly meetings over a two-year period to jointly examine the interconnection experience as it unfolds in Massachusetts as well as across the country, with an eye toward further improving the standards proposed herein over time. The Collaborative will report back annually to the DTE with its findings and any recommendations for further refinements and improvements, before the DTE's issues its final Order.

The stakeholders have further agreed that the interconnection process should be codified as an interim tariff consistent across all the utilities. We were not able to finalize the language of the interim tariff in the time allotted and respectfully request a deadline of April 15 to finish it.

This Report is not intended to replace or change the regulations promulgated under 220 CMR §8.00.

On behalf of the Collaborative, we appreciate the Commission's sanctioning of this process, thank the Massachusetts Technology Collaborative for providing resources, and trust that the Commission will find it time well spent.

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Appendices

Section 1: Introduction and Collaborative Process Overview

The Massachusetts Distributed Generation Interconnection Collaborative ("Collaborative"[1]) was initiated at the request of the Massachusetts Department of Telecommunications and Energy ("DTE") through Order 02-38-A. In that Order, the DTE detailed its expectations for the Collaborative as follows:

> "The Department encourages the collaborative to focus on, among other things, the best features of existing interconnection standards, policies, and procedures. The content of the interconnection standards should be guided by, but not be limited to:
>
> a. Simplified, statewide technical interconnection standards for small, distributed generation;
> b. Simplified, statewide technical standards for all remaining distributed generation;
> c. A statewide interconnection agreement;
> d. Interconnection procedures, standardized to greatest extent possible, including provisions that clarify interconnecting to a network system (compared to a radial system) and equipment pre-approval so that conforming components receive pre-approval by the electric distribution companies;
> e. A time schedule for responding to interconnection applications;
> f. A plan to develop and post a generic document describing interconnection procedures;
> g. An administratively efficient dispute resolution process."

The Collaborative's first meeting was in November 2002. The Massachusetts Technology Collaborative (hereinafter "MTC") provided funding for mediation and technical support for the Collaborative. Raab Associates, Ltd. with Suzanne Orenstein provided mediation services, and Navigant Consulting, Inc. provided technical consulting services.

Over twenty organizations actively participated throughout the four-month Collaborative. These organizations are listed below under five separate clusters: DG Providers, Government/Quasi-Government, Consumers, Utilities, and Public Interest Groups. Appendix E presents a full roster of all the participants from each organization that participated in the Collaborative.

[1] In this document, "Collaborative" refers exclusively to the Distributed Generation Collaborative mandated by MA DTE Order 02-38 and should not be confused with the Massachusetts Technology Collaborative or any other collaborative effort.

DG PROVIDERS
Aegis Energy Services
Solar Energy Business Association of New England (SEBANE)
The E-Cubed Company, LLC
Ingersoll-Rand
Northeast Combined Heat and Power Initiative (NECHPI)
Northeast Energy and Commerce Association
RealEnergy
United Technologies Corp.
Keyspan
Plug Power
Trigen Energy
GOVERNMENT/QUASI GOVERNMENT
MA Division of Energy Resources (DOER)
Massachusetts Technology Collaborative (MTC)
Cape Light Compact
CONSUMERS
Associated Industries of Massachusetts
Wyeth Bio Pharmaceutical
UTILITIES
Fitchburg Gas & Electric (Unitil)
ISO-New England
Boston Edison, Cambridge Electric Light, Commonwealth Electric (NSTAR Electric)
WMECO (Northeast Utilities)
MECo/Nantucket Electric (National Grid)
PUBLIC INTEREST GROUPS
Union of Concerned Scientists/Conservation Law Foundation/MA PIRG
Massachusetts Energy Consumers Alliance

The Collaborative met in plenary for eleven days of meetings. In addition, numerous working groups met consistently throughout this period to develop detailed proposals for review by the full Collaborative. An interim filing was provided to the DTE at the end of December, along with a request for additional time to complete its work, which the DTE subsequently granted.

With this report, the Collaborative has completed its recommendations on all the issues identified by the Commission. These recommendations represent a consensus of the diverse members of this Collaborative except on 1 issue noted in the text. The Collaborative is requesting that the Department adopt these recommendations as interim rules, as the Stakeholders have agreed to continue meeting over the next two years to review experience gained in the Commonwealth and elsewhere with an eye to further improving the DG interconnection process.

Section 2 of this report lays out the Collaborative's goals and a description of the plans for an on-going Collaborative. Section 3 provides both a narrative description of the proposed DG interconnection process and detailed figures mapping the process for interconnecting to both radial and network circuits. In Section 4, we outline both the timeframes and fee schedules for interconnection. Section 5 describes the opportunities and special challenges of interconnecting

to network circuits. Sections 6 and 7 delineate the on-going collaborative and proposed dispute resolution process, respectively.

The appendices contain important additional documents. Appendix A includes the proposed standard application form. Appendix B includes the detailed technical interconnection requirements, and Appendix C includes the information tracking form. Appendix D contains the proposed outline for the interconnection tariff. The tariff will also include a definitions section. Appendix E contains all the stakeholders and organizations that have participated in the Collaborative process. Finally, Appendix F contains an alternative time frame proposal.

Section 2: Goals and On-Going Collaborative

The Collaborative has agreed on the following goals to guide DG interconnection now, and in the future:

For Both Radial and Network Interconnections:

a. Establish uniformity between the Companies where applicable without sacrificing existing efficiencies in current interconnection standards or other customer services.
b. Incorporate the best features of existing interconnection policies and procedures nationally, and take into account the FERC ANOPR process.
c. Maintain or exceed the current level of system reliability.
d. Maintain or exceed the current level of safety to the Company work force and the public.
e. Expedite the timeframes for interconnection approvals.
f. Establish minimal fees appropriate to the scope of work, based upon experience.
g. Develop a cost-effective process that allows a Customer/Installer to determine within a predictable timeframe the expected scope and cost of the interconnection process.
h. Establish expeditious and cost-effective approaches for interconnecting on spot and area networks.

Description of Proposed On-Going Collaborative:

The DG Collaborative has agreed to meet quarterly over the next two years to examine the experience with interconnections in Massachusetts and elsewhere in the United States, in an attempt to further streamline the approval timeframes and appropriately adjust the fees associated with interconnection. In order to continuously improve the DG interconnection process, information about the time required, costs, screening steps, and dispute resolution will be tracked by the utilities and aggregated on a quarterly basis. The Information will be reported to the DTE annually, and it is expected that the DTE will make the information available to other agencies and to the public. The DG Collaborative parties will review the information and suggest any improvements to the process that they agree are necessary or desirable after one and two years of experience with DG interconnection under the process recommended by the Collaborative. [See Section 6 below for more details on the on-going Collaborative]

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Section 3: Process for Distributed Generation Interconnection in Massachusetts

There are three basic Company review paths for interconnection of DG in Massachusetts.[2] They are described below and detailed in Figures 1 and 2 with their accompanying notes. Tables 1 and 2, respectively, describe the timelines and fees for these paths.

1. **Simplified** – This is for qualified inverter-based facilities with a power rating of 10 kW or less on radial or spot network systems under certain conditions.
2. **Expedited** – This is for certified facilities that pass certain pre-specified screens on a radial system.
3. **Standard** – This is for all facilities not qualifying for either the Simplified or Expedited interconnection review processes on radial and spot network systems, and for all facilities on area network systems.

All proposed new sources of electric power in the Company system, without respect to generator ownership, dispatch control, or prime mover, that plan to operate in parallel with the Company system must submit a completed application and pay the appropriate application fee to the Company it wishes to interconnect with. The application will be acknowledged by the Company, and the Customer will be notified of the application's completeness. Customers who are not likely to qualify for Simplified or Expedited review may opt to go directly into the Standard Review path. Customers proposing to interconnect on area networks will also go directly to Standard Review. All other customers must proceed through a series of screens to determine their ultimate interconnection path. (Customers not sure whether a particular location is on a radial circuit, spot network, or area network should check with the Company serving the proposed DG location prior to filing and the Company will verify the circuit type upon filing.)

Customers using qualified (certified to UL 1741) inverter-based facilities with power ratings of 10 kW or less requesting an interconnection on radial systems where the aggregate generating facility capacity on the circuit is less than 7.5% of circuit annual peak load qualify for Simplified interconnection. This is the fastest and least costly interconnection path. There is also a Simplified interconnection path for qualified inverter-based facilities on spot networks under certain conditions.

Other customers not qualifying for Simplified review or not in Standard Review must pass a series of screens before qualifying for Expedited interconnection. If one or more screens are not passed, the Company will offer to conduct a Supplemental Review. If there is any additional fee associated with Supplemental Review not already covered by the application fee and the Customer agrees to pay it, the Company will conduct the review. If the Supplemental Review determines the requirements for processing the application through the Expedited process (including any system modifications), then the modification requirements, reason for needing them, and costs for these modifications will be identified and included in the executable Expedited interconnection agreement.

It is important to note that as part of the Expedited interconnection process, the Company will assess whether any system modifications are required for interconnection, even if the project

[2] If the generation will always be isolated from the Company's system, (i.e., it will never operate in parallel to the Company's system), then these requirements do not apply.

passes all of the applicable screens. If the needed modifications are minor, that is, they can be determined by the Company within the engineering time covered by the application fee, then the Company will identify the modification requirements, reason(s) for them, and cost to perform them, all of which it will include in the executable expedited interconnection agreement. If the requirements cannot be determined within the time and cost alloted in the Initial Review, the Company may require that the project undergo additional Supplemental Review to determine those requirements within the time allocated for Supplemental Review (maximum 10 hours of engineering time). If after these reviews the Company still cannot determine the requirements, the Company will document the reasons why and will meet with the Customer to determine a new schedule to their mutual satisfaction (this is not the Standard Review process). In all cases, the Customer will pay for the cost of modifications that are attributable to its proposed project.

If the facility fails any of the applicable screens and system modifications requirements cannot be determined during the time allotted for Supplemental Review, then the facility enters Standard Review and the Company will provide cost estimates and a schedule for the completion of interconnection study(ies). Upon acceptance by the Customer of the costs, the Company will perform impact and facility studies as required. The Standard interconnection process has the longest maximum time period and highest potential costs.

When the interconnection review is complete and the Company issues an executable agreement under the Expedited and Standard Review paths, the Customer will need to return a signed agreement, complete the installation, and pay any system modification costs identified in the agreement. The Company may inspect the completed installation for compliance with standards and schedule a witness test. Assuming the inspection is satisfactory, the Company notifies the Customer that interconnection is allowed. A parallel but simpler process exists for Simplified interconnections. If the Customer does not sign the agreement or complete construction within a certain time period yet to be determined, the Customer may need to reapply for interconnection.

Table 1 lays out the maximum timeframes allowed under the Simplified, Expedited, and Standard Review processes for each step in the review processes (application approval, review of screens, Supplemental Review, facility and impact studies, and sending an executable agreement – note that some of these steps are not required for every review process) and for the processes as a whole. The maximum time allowed for the Company to execute the entire Simplified process is 15 days; 40 days for the Expedited process on a radial system where no Supplemental Review is needed and 60 days where it is; 125 days for the Standard Review process if the Customer goes directly to Standard Review and 150 days if the Customer goes from the Expedited process into Standard Review. For Customers qualifying for the Simplified process on a spot network, the maximum time is 40 days if load data is available and 100 days if it is not. The maximum times refer to Company working days, and the Company clock is stopped when awaiting information from Customers.

Table 2 lays out the commercial terms (i.e., fees) required for Customers to apply for interconnection. There are no fees for those facilities that qualify for the Simplified path (except in certain unique cases where a system modification would be needed which would be covered by the Customer). Those qualifying for Expedited review on a radial system will pay a $3/kW application fee (minimum of $300 and maximum of $2,500) plus $125/hour up to 10 hours ($1,250) for Supplemental Review, when applicable, plus the actual cost of any required facility upgrades. Those on the Standard Review path would pay the same application fee as in the Expedited path as well as the actual cost of any required facility upgrades, plus the actual cost of

any impact and facility studies, if required. Facilities qualifying for the Simplified process on a spot network will pay a flat application fee of $100 for 3kW or less, and $300 for facilities up to and including 10 kW, plus any system modification costs.

Dispute resolution procedures will be available to address disagreements about the DG interconnection process for specific projects. The dispute resolution process includes three steps: (1) negotiation with elevation to senior management, (2) neutral mediation that includes a neutral technical expert if appropriate followed by non-binding arbitration if the parties cannot reach agreement, and (3) an adjudicatory hearing at the DTE. The negotiation step will be initiated and conducted by the disputing parties themselves. The mediation/non-binding arbitration step will be conducted by a private mediator, with technical experts as needed, and will be convened by the DTE. If these two steps are not successful, the parties will request a hearing at the DTE. It is anticipated that the DTE hearing will be somewhat expedited by the availability of information developed in Step 2, and that all parties will work to proceed as quickly as possible to resolution of the dispute.

Figure 1: Schematic of Massachusetts DG Interconnection Review Process

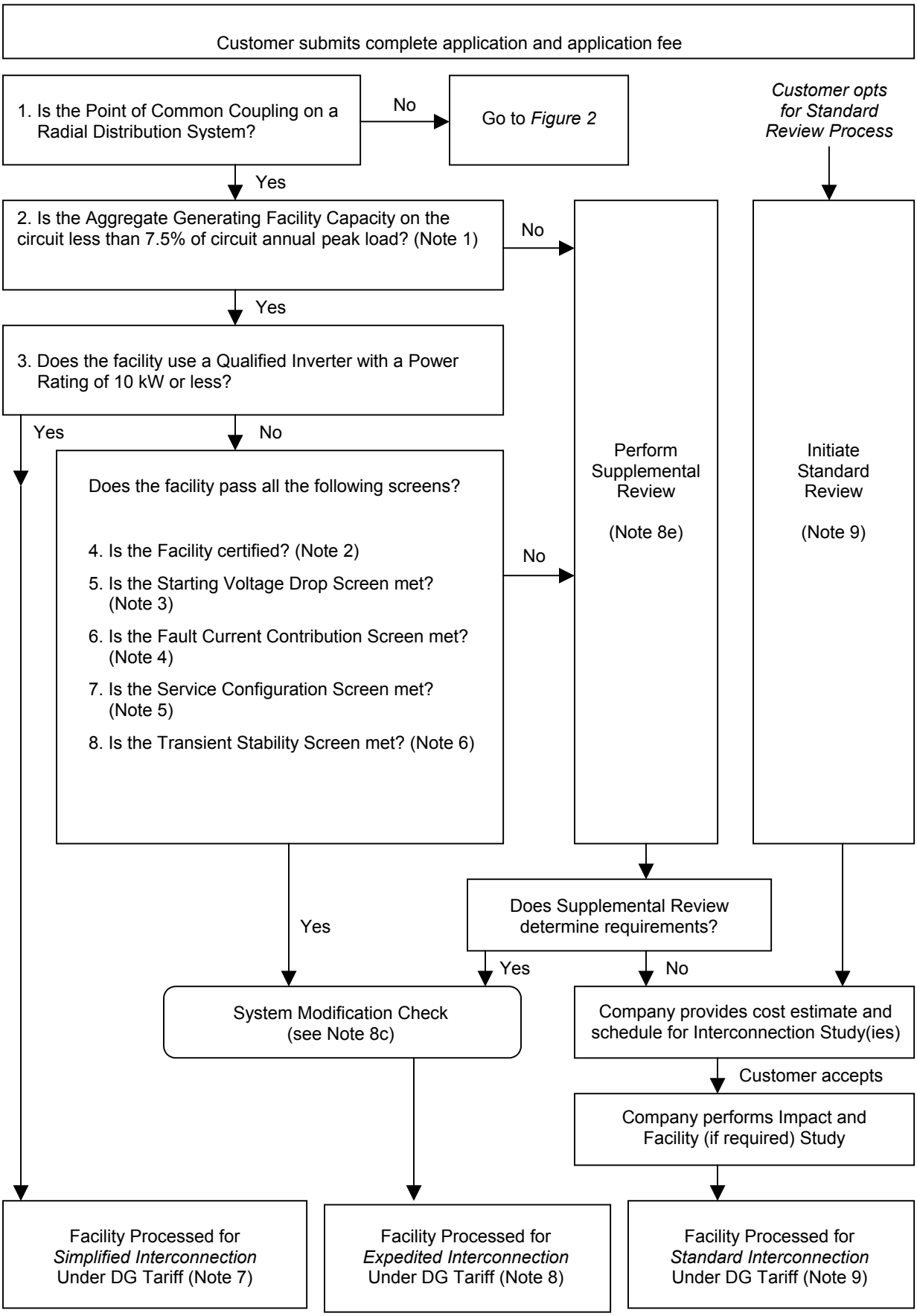
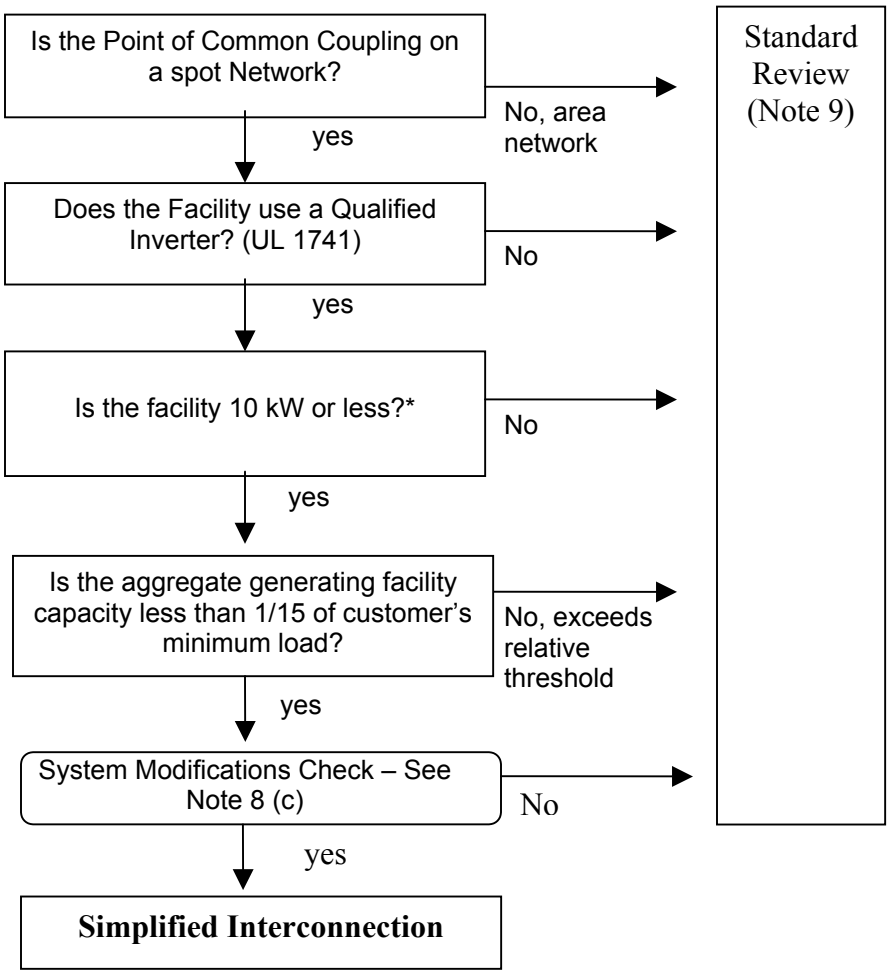


Figure 2 - Simplified Interconnection to Networks



*The Collaborative agrees to endeavor to increase this maximum size over time as experience is gained and/or advances in technology warrant.

Explanatory Notes to Accompany Figures 1 and 2

Note 1. On a typical radial distribution system circuit ("feeder") the annual peak load is measured at the substation circuit breaker, which corresponds to the supply point of the circuit. A circuit may also be supplied from a tap on a higher-voltage line, sometimes called a subtransmission line. On more complex radial systems, where bidirectional power flow is possible due to alternative circuit supply options ("loop service") the normal supply point is the loop tap.

Note 2: California and New York have adopted certification rules for expediting application review and approval of Generating Facility interconnections onto Company electric systems. Generating Facilities in these states must meet commission-approved certification tests and criteria to qualify for expedited review. Since the certification criterion is based on testing results from recognized national testing laboratories, Massachusetts will accept Generators certified in California and New York as candidates for Expedited Review. It is the Customer's responsibility to determine if and submit verification that the proposed Facility has been certified in California or New York.

The above states and Massachusetts have adopted UL 1741, *"Inverters, Converters and Charge Controllers for Use in Independent Power Systems"*, for certifying the electrical protection functionality of independent power systems. UL 1741 compliance is established by nationally recognized testing laboratories. Customers should contact the Facility supplier to determine if it has been listed.

IEEE P1547 Draft Standard includes design specifications and provides technical and test specifications for Facilities rated up to 10MVA. To meet the IEEE standard Customers must provide information or documentation that demonstrates how the Facility is in compliance with the IEEE P1547 Draft Standard. A Generating Facility will be deemed to be in compliance with the IEEE P1547 Draft Standard if the Company previously determined it was in compliance. The Massachusetts Collaborative will identify an appropriate entity to maintain a registry of Generating Facilities previously certified in other states or in compliance with the IEEE standard.

Applicants who can demonstrate Facility compliance with either standard will be eligible for Expedited Review.

Note 3. This screen only applies to Generating Facilities that start by motoring the Generating Unit(s) or the act of connecting synchronous generators. The voltage drops should be less than the criteria below. There are two options in determining whether Starting Voltage Drop could be a problem. The option to be used is at the Companies' discretion:

> Option 1: The Company may determine that the Generating Facility's starting Inrush Current is equal to or less than the continuous ampere rating of the Facility's service equipment.
>
> Option 2: The Company may determine the impedances of the service

distribution transformer (if present) and the secondary conductors to the Facility's service equipment and perform a voltage drop calculation. Alternatively, the Company may use tables or nomographs to determine the voltage drop. Voltage drops caused by starting a Generating Unit as a motor must be less than 2.5% for primary interconnections and 5% for secondary interconnections.

Note 4. The purpose of this screen is to ensure that fault (short-circuit) current contributions from all DG units will have no significant impact on the Company's protective devices and system. All of the following criteria must be met when applicable:

a. The proposed Generating Facility, in aggregation with other generation on the distribution circuit, will not contribute more than l0% to the distribution circuit's maximum fault current under normal operating conditions at the point on the high voltage (primary) level nearest the proposed point of common coupling.
b. The proposed Generating Facility, in aggregate with other generation on the distribution circuit, will not cause any distribution protective devices and equipment (including but not limited to substation breakers, fuse cutouts, and line reclosers), or customer equipment on the system to exceed 85% of the short circuit interrupting capability. In addition, the proposed Generating Facility will not be installed on a circuit that already exceeds 85 percent of the short circuit interrupting capability.
c. When measured at the secondary side (low side) of a shared distribution transformer, the short circuit contribution of the proposed Generating Facility must be less than or equal to 2.5% of the interrupting rating of the Companies' Service Equipment.

Coordination of fault-current protection devices and systems will be examined as part of this screen.

Note 5. This screen includes a review of the type of electrical service provided to the customer, including line configuration and the transformer connection to limit the potential for creating over voltages on the Company system due to a loss of ground during the operating time of any anti-islanding function.

Primary Distribution Line Type	Type of Interconnection to Primary Distribution Line	Result/Criteria
Three-phase, three wire	3-phase or single phase, phase-to-phase	Pass screen
Three-phase, four wire	Effectively-grounded 3 phase or Single-phase, line-to-neutral	Pass screen

If the proposed generator is to be interconnected on a single-phase transformer shared secondary, the aggregate generation capacity on the shared secondary, including the proposed generator, will not exceed 20 kVA.

If the proposed generator is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition will not create an imbalance between the two sides of the 240 volt service of more than 20% of nameplate rating of the service transformer.

Note 6. The proposed generator, in aggregate with other generation interconnected to the distribution low voltage side of the substation transformer feeding the distribution circuit where the generator proposes to interconnect, will not exceed 10 MW in an area where there are known or posted transient stability limitations to generating units located in the general electrical vicinity (e.g., 3 or 4 transmission voltage level buses from the point of interconnection).

Note 7. <u>Simplified Interconnection</u>:

a. Application process:
    i. Customer submits an Application filled out properly and completely.
    ii. Company acknowledges to the customer receipt of the application within three business days of receipt.
    iii. Company evaluates the Application for completeness and notifies the customer within 10 days of receipt that the application is or is not complete.
b. Company verifies Generating Facility equipment passes screens 1, 2, and 3.
c. Company and customer execute agreement (if an agreement is required by the Collaborative). In certain rare circumstances, the Company may require the Customer to pay for minor system modifications.
d. Upon receipt of signed application/agreement and completion of installation, Company may inspect Generating Facility for compliance with standards and may arrange for a witness test.
e. Assuming inspection/test is satisfactory, Company notifies Customer in writing that interconnection is allowed, and approves.

Note 8. <u>Expedited Interconnection</u>:

a. Application process:
    i. Customer submits an Application filled out properly and completely.
    ii. Company acknowledges to the customer receipt of the application within three business days of receipt.
    iii. Company evaluates the Application for completeness and notifies the customer within 10 days of receipt that the application is or is not complete.
b. Company then conducts an initial review which includes applying the screening methodology (screens 1 through 8).
c. *Notice: The Company reserves the right to conduct additional studies if deemed necessary and at no additional cost to the Customer, such as but not limited to: protection review, aggregate harmonics analysis review, aggregate power factor review and voltage regulation review. Likewise, when the proposed interconnection may result in reversed load flow through the Company's load tap changing transformer(s), line voltage regulator(s), control modifications necessary to mitigate the effects may be made to these devices by the Company at the Interconnecting Customer's expense or the Facility*

may be required to limit its output so reverse load flow cannot occur or to provide reverse power relaying that trips the Facility. As part of the expedited interconnection process, the Company will assess whether any system modifications are required for interconnection, even if the project passes all of the applicable screens. If the needed modifications are minor, that is, the requirement can be determined within the time allotted through the application fee, then the modification requirements, reasoning, and costs for these minor modifications will be identified and included in the executable expedited interconnection agreement. If the requirements cannot be determined within the time and cost alloted in the initial review, the Company may require that the project undergo additional review to determine those requirements. The time allocated for additional review is a maximum of 10 hours of engineering time. If after these reviews, the Company still cannot determine the requirements, the Company will document the reasons why and will meet with the customer to determine how to move the process forward to the parties' mutual satisfaction. In all cases, the Customer will pay for the cost of modifications that are solely attributable to its proposed project.

d. Assuming all applicable screens are passed, Company sends the Customer an executable agreement and a quote for any required system modifications or reasonable witness test costs.
e. If one or more screens are not passed, the Company will offer to conduct a Supplemental Review. If the Customer agrees to pay the Supplemental Review Fee, the Company will conduct the review. If the Supplemental Review determines the requirements for processing the application through the expedited process including any system modifications, then the modification requirements, reasoning, and costs for these modifications will be identified and included in the executable expedited interconnection agreement. If this is not true, the Supplemental Review will include an estimate of the cost for the studies that are part of the Standard Review process. Even if a proposed project initially fails a particular screen in the Expedited process, if Supplemental Review shows that it can return to the Expedited process then it will do so. Supplemental Review includes up to 10 hours of engineering time.
f. Customer returns signed agreement
g. Customer completes installation.
h. Company completes system modification, if required.
i. Company inspects completed installation for compliance with standards and attends witness test, if required.
j. Assuming inspection is satisfactory, Company notifies Customer in writing that interconnection is allowed.

Note 9. <u>Standard Review Process</u>

a. Customers may choose to proceed immediately to the Standard Review process. Application process:
    i. Customer submits an Application filled out properly and completely.
    ii. Company acknowledges to the customer receipt of the application within three business days.
    iii. Company evaluates the Application for completeness and notifies the customer within 10 days whether the application is complete.

b. Based upon the results of the initial and Supplemental Reviews, customers may be required to enter the Standard Review process.
    i. The Company will conduct a scoping meeting/discussion with the customer (if necessary) to review the application. At the scoping meeting the Company will provide pertinent information such as:
        a. The available fault current at the proposed location;
        b. The existing peak loading on the lines in the general vicinity of the facility,
        c. The configuration of the distribution lines.
    ii. Company develops Impact and/or Facility Study Proposal, including a cost estimate.
    iii. Customer agrees to pay.
    iv. Company performs Impact and/or Facility Studies as agreed to.
    v. Company sends the Customer an executable agreement and a quote for any required system modifications or reasonable witness test costs.
    iv. Customer returns signed agreement
    v. Customer completes installation.
    vi. Company completes system modification, if required.
    vii. Company inspects completed installation for compliance with standards and attends witness test, if required.
    viii. Assuming inspection is satisfactory, Company notifies Customer in writing that interconnection is allowed.

Section 4: Time Frames and Fee Schedules

Table 1: Time Frames* (Note 1)

	Track			
Review Process	Simplified	Expedited	Standard Review	Simplified Spot Network
Eligible Facilities	Certified Inverter ≤ 10 kW	Qualified DG	Any DG	Certified Inverter < ≤
Acknowledge receipt of Application	(3 days)	(3 days)	(3 days)	(3 days)
Review Application for completeness	10 days	10 days	10 days	10 days
Complete Review of all screens	10 days	25 days	n/a	Site review 30/90 days (Note 2)
Complete Supplemental Review (if needed)	n/a	20 days	n/a	n/a
Complete Standard Interconnection Process Initial Review	n/a		20 days	n/a
Send Follow-on Studies Cost/Agreement	n/a		5 days	n/a
Complete Impact Study (if needed)	n/a		55 days	n/a
Complete Facility Study (if needed)	n/a		30 days	n/a
Send Executable Agreement (Note 3)	Done	10 days	15 days	Done (comparable to simplified radial)
Total Maximum Days (Note 4)	15 days	40/60 (Note 5)	125/150 days (note 6)	40/100 days
Notice/ Witness Test	< 1 day with 10 day notice or by mutual agreement	1-2 days with 10 day notice or by mutual agreement	By mutual agreement	1 day with 10- day notice or by mutual agreement

All signatories to this report but one have agreed to these starting timeframes as part of the comprehensive, inter-related interconnection approach presented in this report. RealEnergy, while supporting the other recommendations in this report, cannot support this one. See Appendix F for their alternative recommendation for shorter timelines and their rationale.

Table 2: Fee Schedules

	Track			
Review Process	Simplified	Expedited	Standard Interconnection Process Review	Simplified Spot Network
Eligible Facilities	Certified Inverter ≤ 10 kW	Qualified DG	Any DG	Certified Inverter ≤ 10 kW
Application Fee (covers screens)	0 (Note 1)	$3/kW with minimum fee $300, maximum fee $2,500	$3/kW with minimum fee $300, maximum fee $2,500	$100 for less than or equal to 3kW, $300 if >3kW
Supplemental Review or additional review (if applicable)	n/a	Up to 10 engineering hours at $125/hr ($1,250 max) (Note 2)	n/a	n/a
Standard Interconnection Initial Review	n/a	n/a	Included in application fee (if applicable)	n/a
Impact and Facility Study (if required)	n/a	n/a	Actual cost (Note 3)	n/a
Facility Upgrades	n/a (Note 4)	Actual cost	Actual cost	n/a
O and M (Note 5)	n/a	TBD	TBD	n/a
Witness test	0	Actual cost, up to $300 + travel time (Note 6)	Actual cost	0 (Note 7)
ADR costs	TBD	TBD	TBD	TBD

Explanatory Notes to Accompany Tables 1 and 2

Table 1: Time Frames

Note 1. All days listed apply to Company work days under normal work conditions. All numbers in this table assume a reasonable number of applicants under review. All timelines may be extended by mutual agreement. Any delays caused by Customer will interrupt the applicable clock. Moreover, if a Customer fails to act expeditiously to continue the interconnection process or delays the process by failing to provide necessary information within a reasonable time (e.g. fifteen days), then the Company may terminate the application and the Customer must re-apply. However, the Company will be required to retain the work previously performed in order to reduce the initial and Supplemental Review costs incurred for a period of no less than 1 year
Note 2. 30 days if load is known or can be reasonably determined, 90 if it has to be metered.
Note 3. Utilities deliver an executable form. Once an executable agreement is delivered by the Company, any further modification and timetable will be established by mutual agreement.
Note 4. Actual totals laid out in columns exceed the maximum target. The parties further agree that average days (fewer than maximum days) is a performance metric that will be tracked.
Note 5. Shorter time applies to Expedited with out Supplemental Review, longer time applies to Expedited with Supplemental Review.
Note 6. 125 day maximum applies to a Customer opting to begin directly in Standard Review, and 150 days is for a Customer who goes through initial Expedited Review Process first. In both cases this assumes that both the Impact and Facilities Studies are needed. If both studies are not needed, the timelines will be shorter.

Table 2: Fee Schedules

Note 1. If the Company determines that the Facility does not qualify for the Simplified process, it will let the customer know what the appropriate fee is.
Note 2. Supplemental Review and additional review are defined in Note 8 of Figure 1.
Note 3. This is the actual cost only attributable to the applicant. Any costs not expended from the application fee previously collected will go toward the costs of these studies.
Note 4. Not applicable except in certain rare cases where a system modification would be needed. If so, the modifications are the customer's responsibility.
Note 5. O & M is defined as the Company's operations and maintenance carrying charges on the incremental costs associated specifically with serving the DG Customer. However, the Collaborative recognizes that who should pay and how the charges should be allocated should be taken up in the next phase of the DTE's docket.
Note 6. The fee will be based on actual cost up to $300 plus driving time, unless Company representatives are required to do additional work due to extraordinary circumstances or Customer-side problems (e.g., Company representative required to make two trips to the site), in which case Customer will cover the additional cost.
Note 7. Unless extraordinary circumstances.

Section 5: Overview of Network Interconnection Opportunities and Challenges for DG

I. Overview of Network Interconnection

The Collaborative acknowledges that interconnecting DG to secondary networks poses certain additional challenges compared to interconnecting to radial circuits. As such, the Collaborative has agreed to the following with respect to network interconnections:

1. Allow certain small, inverter-based facilities on spot networks to interconnect through a Simplified process. The remainder of the Generating Facilities would be processed through the Standard review process for now. (See Section 3 above)

2. Set a goal to seek expeditious and cost-effective approaches for interconnecting on spot and area networks (See Section 2 above)

3. Form a technical working team under the umbrella of the ongoing Collaborative to study network interconnection experience and procedures in the Commonwealth and elsewhere in the United States to accomplish point 2.

4. Provide regulators, customers, DG providers, Company personnel, and others with a clear explanation of the opportunities, challenges, and potential solutions posed by interconnecting to networks (as described in this Section).

Opportunities

There are generally two types of distribution systems, radial and secondary network. Many downtown areas of cities are served by, underground low voltage secondary network systems (e.g., Boston, Springfield, Worcester). How far those networks extend and where the network ends and radial distribution begins is a function of the density of the load, economics, and a number of other related factors. Facilities in the center of downtown areas are more likely to be on underground networks, whereas facilities in suburban and rural areas are more likely to be on overhead or underground radial distribution systems. Commercial and residential customers located within urban areas served by secondary networks may want to install Generating facilities.

Challenges

In a secondary network distribution system, service is provided through multiple transformers as opposed to radial systems where there is only one path for power to flow from the distribution substation to a particular load. The redundancy implicit in this design provides multiple potential paths through which electricity can flow, so as to meet the higher reliability needs commonly found in urban areas. When properly designed and maintained, the loss of any single low or high voltage facility usually does not cause an interruption in service.

The secondary sides of network transformers are connected together to provide multiple potential paths for power that will have greater reliability than an equivalent radial feeder with the same power delivery capability. To keep power from inappropriately feeding from one transformer

back through another transformer (feeding a fault on the primary side, for example), devices called network protectors are used to detect such a back feed and open very quickly (within a few cycles). Most network protectors in service have not been designed or tested to operate as a switching device for generators. The interconnection solution has to ensure that the network protector will not be subject to this condition.

Networks thus present four unique challenges for interconnection relative to radial grids:

- Technical Complexity
- Maintaining Network Reliability
- Costs
- Operator Safety

Technical Complexity

The complexity of the integrated network systems raises more technical issues than those that must be resolved compared to radial systems. Network studies usually take longer than radial systems because the network arrangement is more complex and requires more sophisticated methods and tools to properly analyze.

Maintaining Network Reliability

Appropriate steps need to be taken when interconnecting a Generator to assure that the overall reliability of the network system is not diminished. The protection systems needed to prevent back feeding of power through network transformers create additional design challenges for interconnection on network systems, insofar as distributed generators have the *potential* to impact not only power on the grid, but also the grid protection hardware itself if protective measures are not taken. The interconnection of the DG to the network system will affect the power flow and the impact needs to be assessed.

The potential impacts on network protectors include but are not limited to:

1) The inadvertent operation of network protectors under normal (non-fault) conditions: In this condition, if the aggregate Generator output connected to a networked secondary system exceeds the network aggregate load, (e.g., a power-export condition) the excess power will activate all the network protectors unless the protector and generator controls have been modified to accommodate the Generator. If such a situation were allowed, the reliability of the secondary network would be degraded, with the attendant loss of supply to other customers served by the network. In circumstances where some, but not all protectors open due to local generation, grid reliability or power quality still could be unacceptably compromised.

2) The inadvertent opening of network protectors under fault conditions: In this condition, fault current fed from Generators could cause network protectors to open for faults occurring on the primary side of a network transformer, potentially isolating the entire secondary network with a complete loss of supply to all other customers served by the network. In some cases, the Generator fault current contribution could exceed the equipment ratings of secondary equipment, leading to potential equipment failure(s) and interruptions to other network customers.

Costs

The cost of networks systems is much higher than radial systems due to the redundancy, underground location, right-of-way fees in urban areas and higher cost equipment. In some cases, the complexities identified above with respect to network interconnection may also increase the cost to interconnect small generators. This combination of high existing investment and *potentially* high investment for generator interconnection creates many unique financial considerations relative to radial systems.

Mitigating a Generator's network system impacts is likely to be more expensive than on radial systems due to the higher cost of secondary equipment and the greater complexity of the solution. These higher cost mitigation options may be necessary to ensure system reliability and operator safety.

Magnitude of the Challenges and Opportunities

The challenges vary by the size of the Generating facility, type of utility network system, and the size, type of technology and location on the utility system. In large cities a number of utilities use a low-voltage network method of distribution. These low-voltage networks systems are of two major subtypes, the *secondary network* (also referred to as an area network, grid network or street network) and the *spot network.* Secondary networks serve numerous sites, usually a several city blocks, from a grid of low-voltage mains at 120/208 volts, three-phase.

Spot networks serve a single site, usually a large building or even a portion of a large building. The secondary voltage is often 277/480 volts, three-phase, but 120/208 spot networks are also used. Spot networks are supplied from two or more primary distribution feeders through integrated transformer/breaker/protection combinations called *network units.*

A spot network poses fewer but still significant challenges than an area network. The electrical behavior of spot networks also is more predictable than area networks, which makes the task of evaluating the Generator's impacts less difficult than area systems.

II. Challenges and Solutions for Potential Generators/Customers Interested in Interconnecting to Secondary Network Distribution Systems

This section discusses in greater detail the specific challenges Customers may encounter when requesting interconnection to a secondary network. It also describes potential solutions to resolve challenges associated with interconnection to secondary networks. It explains network interconnection issues relative to:

- Generating Facility Size and Characteristics
- Technology Type
- Location
- Exporting
- Load Characteristics
- Network Protector Capability

This section presents interconnection alternatives that may be applicable. Customers who will be interconnecting via the Standard Review Process outlined in Figure 2 are encouraged to read text and articles on this subject.

What are the specific challenges?

Challenges that an applicant may encounter when requesting Generator interconnection to a secondary network system include:

1. **Generator size versus network load**: If the network load is highly variable such that evening or weekend loads are much smaller than daily peaks, the maximum allowable size of the Generator is limited by the maximum allowable generator output at any given time. Particular attention must be given to loads that may, even momentarily, be completely shut down for maintenance or other reasons.

2. **Generator Type**: The degree of complexity of the challenges Generators may encounter also is a function of type of Generator the customer chooses to install. For similar sized Generators, network loads and configurations, inverter-based interconnections pose fewer technical challenges than induction generators, while induction generators raise fewer technical issues than synchronous generators. Inverter-based Generator produce relatively small fault currents compared to rotating machines, typically ranging from 100 to 200% of maximum normal output. Fault currents and transient voltages may be much higher for rotating machines. Inverters also shut down automatically when the secondary network is de-energized. Induction generators also will shut down (i.e., stop producing fault current) on the order of a few cycles – a fraction of a second – when voltages on the generator terminals are sufficiently low to cause induction field voltages to collapse. Synchronous generators will continue to operate and supply fault current until protective relays open circuit breakers to isolate the Generator from the network system. The synchronous generator must not be allowed to operate as an isolated unintended "island" created by open protectors that form the island. Faults external to the primary feeders serving the network also could cause protectors to operate for synchronous generators.

3. **Spot Versus Area Networks**: The complexity of area network compared to spot networks poses additional challenges for Generators. Area networks typically have a greater number of transformers and protectors, primary and secondary lines and more customers than spot networks, thereby increasing the level of effort needed to analyze proposed interconnections. Equally important is the greater variability and unpredictability of load patterns that network transformers may encounter. The maximum allowable size of the Generator on a grid network must be determined via network simulation methods that consider the variability in loads and power flows on the secondary networks. Spot network generally will be able to accommodate larger Generators, all else being equal, than area networks. Spot network transformer loadings tend to be more balanced than area network transformer loadings and Generator impacts are more predictable, and therefore more straightforward to mitigate.

4. **Equipment Standards and Withstand Capability**: Network protectors and other equipment on the network may not be designed and rated to withstand the voltages and currents that may be produced by Generators under some conditions. Network protectors

are not designed to synchronize or disconnect the utility system from Generators located on the secondary side of the network transformer. The protector relays also are not designed to reclose a constant frequency utility network to a Generator. Out-of-phase reclosing could cause the protector to fail. The rating or duty of the transformer, protector and other devices also could be exceeded due to the current contribution of the Generator as well. IEEE P1547 also states that protectors should not be used to back up Generator breakers.

5. **Operator Safety:** Safety rules for operating on networks must be consistent with Company safety requirements.

How would a Company likely address these challenges?

As the total Generating capacity on a secondary network grows relative to total network load, so does the likelihood of reverse power flow through one or more network protectors, thereby causing them to open and potentially interrupt customers or degrade service quality. Consequently, the utility may need to conduct power flow studies to determine whether protectors would likely experience reverse power flows and unintended operations from Generator output.

Alternative schemes for interconnection

While there are many challenges associated with network systems that Generators may not encounter on radial systems, a range of solutions also may be applicable to mitigate the impacts cited above. Each of the solutions below may solve a particular problem, but do not necessarily resolve all the problems a given installation may present on a grid network. Potential solutions currently range from economically feasible to prohibitively expensive.

1. **Radial Interconnection**: If the power flow study determines that the Generator installation could cause unintended operation of the network protector, the most direct way to mitigate this problem is to install the Generating facility on a dedicated radial line, isolated from the network. The dedicated line could be served from the same substation as the network. The dedicated line could connect to one of the primary feeders serving the secondary network, but highly secure transfer tripping schemes will be required for such connections.

2. **Generator Size Selection**: Select a Generator size that will be sufficiently below minimum network loads so as to mitigate the system impacts described herein. For example, if the size of the generator is sufficiently small relative to network loads that reverse power flows will not occur under all loading conditions, the likelihood that network upgrades or special protection options will be needed is reduced. If the Generator is qualified under UL 1741 and is less than 10kW, it may qualify for Simplified Interconnection.

3. **Protection Coordination**: Time coordinate the network protector relay to ensure protectors will not operate due to power flow contributions from the Generator; that is, install time delays on the protector that will cause Generator relays to operate prior to the

protector for low levels faults or power flows. The time delay option is accomplished using a microprocessor-based relay. Many existing protector relays are electro-mechanical and may need to be replaced if this option applies. A related option is to time-coordinate power flows on the network protector and isolate or reduce output from the Generator whenever flows across the protector drop below a specified level. The time delay has the potential to reduce power quality to below desirable levels. A similar option is to install a load totalizer on critical load buses and isolate the Generator whenever reverse power flows occur on that bus. In all cases, the size of the Generator may need to be limited in order to maintain power quality.[3]

4. **Network Upgrades**: Upgrade key network system components, such as protectors or relays, with modern devices designed to withstand the currents and voltages that may be produced by Generators. For example, network protectors may soon be available that are rated to include high interruption capability and separation capability (i.e., breaker capability).

5. **Network Expansion or Reconfiguration**: It may be possible to reconfigure or expand a grid network to obviate the need for dedicated facilities or to mitigate the possibility of unintended reverse power flows on network protectors. In most circumstances, such upgrades would not be cost-effective; however, larger or an extensive number of smaller Generator on a network possibly could justify the modifications if the upgrades are reasonably minor.

In addition to the five mitigation items cited above, there will be other issues and candidate solutions to resolving some, but not necessarily all of the technical challenges raised above. Examples of other potential approaches to be examined further for technical feasibility include:

1. **Reverse Power Flow Mitigation**: The approach to protecting against power backflow discussed in Section 3 above involves metering and totalizing the flows through multiple network feeders to ensure that flow through the network protectors is always towards the load. A simpler and less expensive approach is to measure the customer's load against the output of the generator and either adjusting the generator output to stay below the customer load or isolate the customer's load and generator from the grid.

   A scheme which used a breaker to isolate all or just critical load from the network service would inherently meet the requirement of supplying a back-up breaker for the generator breaker.

2. **Secondary Network Fault Duty Current Assessment and Mitigation**: The amount of potential short circuit available from a generator must be viewed in context with the spot network to which it interconnects. In many cases, the short circuit available from the utility system through network feeders may dwarf the potential contribution from the DG. For example, consider a spot network with three feeders (and network protectors)

[3] An experimental installation is currently underway to assess the performance of spot network systems where protector clearing times are delayed under non-fault conditions to coordinate with DG protection system. Although these protection systems apply only to spot networks, they offer promise to some DG applications, provided their performance is acceptable to utilities and consistent with industry practices.

connected to a common bus. In the event of a fault on the primary side of the transformers, the network protector on that feeder would see the potential fault current available from the utility system through the remaining two feeders. The potential fault current from the DG would not be seen at the other two network protectors.

Where the short circuit of the generator may be significant is for faults on or in the vicinity of the network bus. There are a number of straightforward solutions that may mitigate short circuit current from exceeding the breaker duties in the facility and the ratings of the network protectors. For example, it may be possible to apply simple current limiting fuses to disconnect a customer's generation in less than 1 cycle as a means of mitigating breaker duty stress on the low-voltage breakers. Such an application would likely require negative sequence protection of the generator.

For relatively small units (< 500 kw), contactors can be substituted for breakers and can be opened in less than 2 cycles.

3. **Mitigating Excessive Fault Duty on the Utility Substation Bus**

In some systems the utility substation bus may be already near its equipments maximum fault duty capability. In such cases, even a modest addition of generation on the network grid may cause fault currents that will exceed bus breaker ratings. Because the network protector tripping must be delayed to give time for the generator breaker(s) to clear, the substation breaker responsible for clearing the fault will see the generator contribution during its clearing time. Such conditions might be resolved by the addition of current limiting reactors to the feeders supplying the network with generation. However the impact on power quality at the network bus would have to be reassessed.

Section 6: On-Going Collaboration and Information Tracking

Annual Review and Information Tracking Proposal

Goals for Information Tracking and Progress Review

DG Collaborative members have agreed, based on projections of future needs and capabilities, to components of a system to streamline DG interconnection procedures. All Collaborative parties agree that, because DG is an emerging interconnection arena, there is limited experience with the screens, time lines, and cost estimates that are part of the recommended interconnection process. Many parties in the Collaborative agreed to the recommended interconnection process on condition that a process be developed to assess the efficiency and effectiveness of the process and to work together in the future to create the most reliable, safe and efficient system for all parties. Thus, the Collaborative as a whole recommends that the DTE issue an Interim Order implementing the DG Collaborative report and that the DTE authorize the Collaborative to undertake a two-year review process for DG interconnection experiences under the Collaborative recommended procedures.

Collaborative members further agree to gather, aggregate, and review project-specific information to provide data on which to evaluate the effectiveness of the proposed system. Available data will be provided to the DG Collaborative and the Massachusetts DTE. This data may also be provided by the DTE to others interested in DG interconnections, including relevant agencies (e.g. DEP) and organizations (e.g. ISO-New England). This data will be collected for new or proposed power producers operating in parallel to the Company system without respect to Generator owner, dispatch control, or prime mover.

Forum for Periodic Review

The Collaborative will formally review information about the interconnection process on a quarterly basis. After one year of experience and again after two years, the Collaborative, at its option, may request modifications in the Interim Order so that it can begin to implement any necessary adjustments, improvements and streamlining that all members can support at that time. At the end of the first year the Collaborative will review topics and potential changes for streamlining the interconnection process for future years. The Collaborative will request a final order at the end of 2 years.

The Collaborative will also submit an annual report to the DTE as a result of its annual review, including any recommended changes to the Interim Order, and any issues on which the parties disagree but want to report to the DTE about those disagreements. The Collaborative believes that DTE's presence in the on-going collaborative would be helpful.

The Collaborative will also meet quarterly to compare notes about experiences with the DG interconnection system. The first meeting will be three months after the DTE issues its Interim Order, and subsequent meetings will be scheduled quarterly thereafter. It will work during its first meeting to organize itself, including establishing information sources and other resources, including facilitation, for the Collaborative.

The purpose of the quarterly Collaborative meetings will be to review projects in the pipeline, determine how uniform the interconnection process is, and to look at general information about the following:

- Number of applications received by the utilities
- How many applications fell within the Simplified, Expedited, and Standard Review processes
- Project size
- Number of projects completed
- Any network issues that have arisen
- Anecdotal experience with the Tariff and the Contract.
- For completed projects: the total Company time and costs to accomplish the interconnection.

Under the umbrella of the Collaborative a technical work team will collectively explore the opportunities and challenges of spot and area network interconnection identified in Section 5, reviewing information and studies related to interconnections in Massachusetts and throughout the country, and considering alternative interconnection techniques. This is not intended to require the Companies to fund research and development.

DTE has charged the Collaborative to develop simplified uniform interconnection standards for Massachusetts that remove barriers to DG interconnection by "considering the best features of existing standards, policies, and procedures." In addition, the DTE specifically requested the Collaborative take into account the recent FERC ANOPR process (RM02-12-000). The Collaborative considered the ANOPR process to date, the demonstrated success of the California Rule 21 simplified process, and the nearly complete emergence of the IEEE P1547 Draft Standard interconnection standards in an effort to identify best practices and procedures for DG interconnection. The DG Collaborative agrees to on-going evaluation of the development of interconnection standards and practices across the nation and seeks to incorporate best features of these other practices in Massachusetts. As experience is gained, at the annual review the Collaborative will evaluate, among other things the following topics and potential changes.

1) Screening process:

Goal is to reduce need for studying issues beyond those covered by the screens. The Collaborative will strive toward industry best practices whereby passing all screens as currently defined will result in further studies, if any, being sufficiently minimal such that additional study fees and time will not be needed.

2) Impact criteria

Verify reasonableness of 7.5 % screen, and as we identify feeders approaching 15% DG saturation, and have fully evaluated their impact (depending on technology type), we'll look to incorporate a 15% screening methodology

3) Standards based

When the IEEE P1547 Draft Standard standards are approved, the Companies will adopt it as minimum requirements for interconnection.

4) Review Duration

Strive to reduce times toward best practices in the industry and meet Customers' Agreement-Needed Date requested in the application 95% of the time.

5) Fees

Assess reasonableness of fees, and strive to reduce them wherever possible.

Data Tracking

The utility company participants in the DG Collaborative have agreed to track certain information on the processing of each application for DG interconnection and to compile that information on an annual basis for presentation and discussion with other Collaborative members. The tracking system will be standard for all electric utility companies in Massachusetts, will be aggregated for each company and across the utilities, and average costs and processing times[4] will be calculated. A report of this information will be shared with Collaborative members and it is also anticipated that this information will be posted annually on the Collaborative's web site for access of other mechanisms and review by others.

The tracking system for applications and project interconnection has been reviewed in the Collaborative process, and was designed to meet the needs of all parties. The information tracking format is presented in Appendix C.

In addition to tracking the processing of each application, the utilities will develop a system that will be used to track each project's progress through the screens used to identify simplified and expedited interconnections. The utilities will seek to establish a uniform approach in their screen tracking efforts. As part of its data tracking, the utility companies will also annually compile and make available the total new DG capacity by Company and by zone.

Confidentiality Protections.

Information including identifying information and specific Generating Facility information may be shared with the DTE. A list of all executed DG interconnection agreements will be submitted to the DTE annually.

In an ongoing effort to improve the interconnection process for customer-owned Generating Facilities, the information provided by Customers and the results of the application process will be aggregated with the information of other applicants and periodically reviewed by a DG Collaborative authorized by the DTE consisting of industry participants. The aggregation process will not reveal specific details for any one customer. In addition to this process, customers may choose to allow non-identifying information specific to their applications to be

[4] The aggregated reports will include information about all applications, not just those completed.

shared with the Collaborative by answering “Yes” to the Confidentiality Statement question on the first page of the application form.

Section 7: Dispute Resolution Steps

The Collaborative recommends a multi-stage dispute resolution process described below, beginning with negotiation, then mediation, followed by non-binding arbitration and then adjudication.

1. Good Faith Negotiation

   A. One party submits a request in writing to the other party for initiation of Step 1 of the Dispute Resolution process. The parties will elevate the dispute to a Vice President or senior management with sufficient authority to make a decision.
   B. If, after eight days, the dispute is still not resolved, one or both parties may initiate Step 2.A.

2. Mediation/Non-binding Arbitration

   A. One party to the dispute requests dispute resolution assistance by submitting a written request to the DTE, with a summary of the situation. The other party may also submit a summary.
   B. The parties will meet with the DTE hearing officer or other DTE staff person within 14 days to convene the dispute resolution process. During that meeting, the DTE staff person may assist the parties in attempting to resolve outstanding differences.
   C. If the differences are not resolved in Step 2.B, the DTE will provide a list of qualified neutrals and manage the selection of individual neutrals for the case. The DTE will use a list of pre-qualified neutrals developed by the DG Collaborative and, the parties will select a mutually agreeable mediator pursuant to a reverse strike out process[5] or another mutually-agreeable method. If either party requests a technical expert, both a mediator and a technical expert will be selected, and the technical expert will be selected using the same strike out process used for selection of the mediator.
   D. Parties will complete the neutral selection process with the DTE within seven days. This timetable will only be possible if the DTE has, during the initial 14 days, identified mediators and technical experts who have the time available to assist the parties in a timely manner.
   E. DTE will arrange for the selected mediator to contact parties.
   F. The parties will contract with neutrals for services, splitting the fees 50/50.
   G. The mediator begins by discussing the case with the disputing parties to assess the scope of issues and understand the parties' positions and interests. The mediator and parties will establish a schedule for completion of mediation within 30 days. Ten days after the 30-day time period begins, the DTE will issue a public notice of the proceeding and will schedule a pre-hearing conference for Step 3. The mediator will assist the parties in developing a scope of work for the technical expert if one is needed. The mediator will also assist the parties in estimating the ADR costs and addressing any concerns about those costs.
   H. Mediation meeting or meetings are held.
   I. If the parties reach agreement, the dispute resolution process ends here.

[5] A "reverse strike out process" involves each party eliminating the least desirable mediator until one is left standing.

J. If the parties do not reach a mediated agreement, the neutral(s) will issue a brief recommended solution or decision.
K. If the parties accept the neutral's recommendation, the dispute resolution process ends here.
L. If one or both parties do not accept the neutral recommendation and there is still no agreement, the dispute proceeds to Step 3.

3. DTE Adjudicatory Hearing

The goal of this Step is an adjudicatory hearing at the DTE, with witnesses, evidence, etc. that results in a binding precedential decision, appealable to the SJC.

A. In the event a party does not accept the recommendation in Step 2, it may request, in writing, a DTE adjudication.
B. DTE holds a pre-hearing conference. The parties, to the extent desirable and feasible, exchange information and establish an expedited schedule during the pre-hearing conference.
C. DTE and the parties engage in pre-hearing discovery, as needed in the specific case, building on the information developed in Step 2, including the mediator's recommendation.
D. DTE conducts a hearing.
E. The parties file briefs, if one or both desire to do so or the DTE requests they do so. The parties and the DTE will complete Step 3.B through 3.E in 90 days.
F. The DTE issues its order within 20 days. If it is unable to do so, it will notify the parties and provide a revised decision date.

The Collaborative recommends that the DG Collaborative develop lists of pre-qualified mediators and technical experts and submit it to the DTE for the DTE's use in assisting the parties to identify a private mediator and/or technical expert for the case. The DG Collaborative further recommends that the DTE appoint a hearing officer or other DTE staff person familiar with the DG interconnection process in Massachusetts to oversee the selection of private neutrals and otherwise serve as a resource for DG cases.

The Collaborative agrees that disputes subject to the dispute resolution process on these issues are not meant to be considered as customer complaints as part of the Companies' service quality plans. The docket numbers for these plans are: for WMECO, D.T.E. 01-66, D.T.E. 01-71, for Massachusetts Electric, D.T.E. 01-71B, for Fitchburg Gas and Electric, D.T.E. 99-84, and for NSTAR D.T.E 01-71A. This does not preclude the Customer from filing customer complaints for which they are otherwise eligible.

Appendix A: Application Form

Attachment __: Generating Facility Interconnection Application

Instructions

General Information **(For all applications)**

Simplified Process applications: For applicants wishing to submit an application for the Simplified Process (<10kW, inverter-based, UL1741-listed) please fill out the first page only down to the space for your signature. Once complete, please sign and attach any documentation provided by the generator manufacturer describing the UL1741 listing for the generator.

Expedited or Standard process applications: All other applicants, please fill out all pages of the application form as it applies to your Generation Facilities. Once complete, please sign and attach the supporting documentation requested.

Contact Information: You must provide as a minimum the contact information of the legal applicant. If another party is responsible for interfacing with the Company (utility), you may optionally provide their contact information as well.

Ownership Information: Please enter the legal names of the owner or owners of the generating facility. Include the percentage ownership (if any) by any electric service company (utility) or public utility holding company, or by any entity owned by either.

Confidentiality Statement: In an ongoing effort to improve the interconnection process for customer-owned Generating Facilities, the information you provide and the results of the application process will be aggregated with the information of other applicants and periodically reviewed by a DG Collaborative of industry participants that has been organized by the Massachusetts Department of Telecommunications and Energy (DTE). The aggregation process mixes the data together so that specific details for one customer are not revealed. In addition to this process, you may choose to allow the information specific to your application to be shared with the Collaborative by answering "Yes" to the Confidentiality Statement question on the first page. Please note that even in this case your identification information (contact data) and specific Generating Facility location will not be shared.

Generating Facility Information **(for all applications)**

UL1741 Listed? This standard ("Inverters, Converters, and Controllers for Use in Independent Power Systems") addresses the electrical interconnection design of various forms of generating equipment. Many manufacturers choose to submit their equipment to a Nationally Recognized Testing Laboratory (NRTL) that verifies compliance with UL1741. This "listing" is then marked on the equipment and supporting documentation.

DEP Air Quality Permit Needed? A Generating Facility may be considered a point source of emissions of concern by the Massachusetts Department of Environmental Protection (DEP). Therefore, when submitting this application please indicate whether your Generating Facility will require an Air Quality Permit, if known. Please contact the DEP (contact info will be added here) to determine whether the generating technology planned for your facility qualifies for a DEP waiver or requires a permit.

Contact Information (For all applications)

Legal Name and address of Customer applicant (or, if an Individual, Individual's Name)

Company Name: _____Contact Person:_____

Mailing Address: _____

City: _____ State: _____ Zip Code: _____

Telephone (Daytime): _____ (Evening): _____

Facsimile Number: _____ E-Mail Address: _____

Alternative Contact Information (if different from Applicant)

Name: _____

Mailing Address: _____

City: _____ State: _____ Zip Code: _____

Telephone (Daytime): _____ (Evening): _____

Facsimile Number: _____ E-Mail Address: _____

Ownership (include % ownership by any electric utility): _____

Confidentiality Statement: "I agree to allow information regarding the processing of my application (without my name and address) to be reviewed by the Massachusetts DG Collaborative that is exploring ways to further expedite future interconnections." Yes_____ No_____

Generating Facility Information (for all applications)

Location (if different from above): _____

_____

Electric Service Company: _____ Account Number (if available): _____

Type of Generating Unit: Synchronous_____ Induction_____ Inverter_____

Manufacturer: _____ Model: _____

Nameplate Rating: _____ (kW) _____ (kVAR) _____ (Volts) Single___ or Three___ Phase

Prime Mover: Fuel Cell___ Recip Engine___ Gas Turb___ Steam Turb___ Microturbine___ PV__ Other__

Energy Source: Solar__ Wind___ Hydro___ Diesel___ Natural Gas___ Fuel Oil__ Other_____ (Specify)

UL1741 Listed? Yes____ No ____

Does facility need an air quality permit from DEP? Yes___ No ___Not Sure____

Planning to Export Power? Yes____ No____ A Cogeneration Facility? Yes____ No_____

Anticipated Export Power Purchaser: _____

Export Form? Simultaneous Purchase/Sale___ Net Purchase/Sale__ Net Metering__ Other_____ (Specify)

Est. Install Date: _____ Est. In-Service Date: _____ Agreement Needed By: _____

Application Process (for all applications)

I hereby certify that, to the best of my knowledge, all of the information provided in this application is true:

Customer Signature: _____ Title: _____ Date: _____

The information provided in this application is complete:

Company Signature: _____ Title: _____ Date: _____

Simplified Process Only (attach manufacturer's cutsheet showing UL1741 listing & stop here)

Interconnection is approved pursuant to Tariff:

Company Signature: _____ Title: _____ Date: _____

Generating Facility Technical Detail (for Expedited and Standard applications)

List components of the Generating Facility that are currently certified and/or listed to national standards

	Equipment Type	Manufacturer	Model	National Standard
1.				
2.				
3.				
4.				
5.				
6.				

Total Number of Generating Units in Facility? _____

Generator Unit Power Factor Rating: _____

Max Adjustable Leading Power Factor? _____ Max Adjustable Lagging Power Factor? _____

Generator Characteristic Data (for all inverter-based machines)

Max Design Fault Contribution Current? _____ Instantaneous ___or RMS? _____

Harmonics Characteristics: _____

Start-up power requirements:_____

Generator Characteristic Data (for all rotating machines)

Rotating Frequency: _____ (rpm) Neutral Grounding Resistor (If Applicable): _____

Additional Information for Synchronous Generating Units

Synchronous Reactance, Xd: _____ (PU) Transient Reactance, X'd: _____ (PU)

Subtransient Reactance, X"d: _____ (PU) Neg Sequence Reactance, X_2: _____ (PU)

Zero Sequence Reactance, Xo: _____ (PU) KVA Base: _____

Field Voltage: _____ (Volts) Field Current: _____ (Amps)

Additional information for Induction Generating Units

Rotor Resistance, Rr: _____ Stator Resistance, Rs: _____

Rotor Reactance, Xr: _____ Stator Reactance, Xs: _____

Magnetizing Reactance, Xm: _____ Short Circuit Reactance, Xd": _____

Exciting Current: _____ Temperature Rise: _____

Frame Size: _____

Total Rotating Inertia, H: _____ Per Unit on KVA Base: _____

Reactive Power Required In Vars (No Load): _____

Reactive Power Required In Vars (Full Load): _____

Additional information for Induction Generating Units that are started by motoring

Motoring Power: _____ (kW) Design Letter: _____

Interconnection Facilities Technical Detail (for Expedited and Standard applications)

Will a transformer be used between the generator and the point of interconnection? Yes____ No____

Will the transformer be provided by Customer? Yes____ No____

Transformer Data (if applicable, for Customer-Owned Transformer):

Nameplate Rating: _____ (kVA) Single ___ or Three ___ Phase

Transformer Impedance: _____ (%) on a _____ KVA Base

If Three Phase:
Transformer Primary: _____ (Volts) ___Delta ____ Wye _____ Wye Grounded ____ Other

Transformer Secondary: _____ (Volts) ___Delta ____ Wye _____ Wye Grounded ____ Other

Transformer Fuse Data (if applicable, for Customer-Owned Fuse):

(Attach copy of fuse manufacturer's Minimum Melt & Total Clearing Time-Current Curves)

Manufacturer: _____ Type:_____ Size: _____ Speed: _____

Interconnecting Circuit Breaker (if applicable):

Manufacturer:_____ Type:_____ Load Rating:_____ (Amps) Interrupting Rating:_____ (Amps) Trip Speed:_____ (Cycles)

Interconnection Protective Relays (if applicable):

(If microprocessor-controlled)
List of Functions and Adjustable Setpoints for the protective equipment or software:

	Setpoint Function	Minimum	Maximum
1.	_____	_____	_____
2.	_____	_____	_____
3.	_____	_____	_____
4.	_____	_____	_____
5.	_____	_____	_____
6.	_____	_____	_____

(If discrete components)
(Enclose copy of any proposed Time-Overcurrent Coordination Curves)

Manufacturer:_____ Type:_____ Style/Catalog No.:_____ Proposed Setting:_____

Manufacturer:_____ Type:_____ Style/Catalog No.:_____ Proposed Setting:_____

Manufacturer:_____ Type:_____ Style/Catalog No.:_____ Proposed Setting:_____

Manufacturer:_____ Type:_____ Style/Catalog No.:_____ Proposed Setting:_____

Manufacturer:_____ Type:_____ Style/Catalog No.:_____ Proposed Setting:_____

Manufacturer:_____ Type:_____ Style/Catalog No.:_____ Proposed Setting:_____

Current Transformer Data (if applicable):

(Enclose copy of Manufacturer's Excitation & Ratio Correction Curves)

Manufacturer:_____ Type:_____ Accuracy Class:_____ Proposed Ratio Connection:_____

Manufacturer:_____ Type:_____ Accuracy Class:_____ Proposed Ratio Connection:_____

Potential Transformer Data (if applicable):

Manufacturer:_____ Type:_____ Accuracy Class:_____ Proposed Ratio Connection:_____

Manufacturer:_____ Type:_____ Accuracy Class:_____ Proposed Ratio Connection:_____

General Technical Detail (for Expedited and Standard applications)

Enclose 3 copies of site electrical One-Line Diagram showing the configuration of all generating facility equipment, current and potential circuits, and protection and control schemes with a Massachusetts-registered professional engineer (PE) stamp.

Enclose 3 copies of any applicable site documentation that indicates the precise physical location of the proposed generating facility (e.g., USGS topographic map or other diagram or documentation).

Proposed Location of Protective Interface Equipment on Property:
(Include Address if Different from Application Address)

_____

_____

Enclose copy of any applicable site documentation that describes and details the operation of the protection and control schemes.

Enclose copies of applicable schematic drawings for all protection and control circuits, relay current circuits, relay potential circuits, and alarm/monitoring circuits (if applicable).

Please enclose any other pertinent information to this installation.

Appendix B: Interconnection Requirements

Policy and Practices for Protection Requirements For New or Modified Generation Interconnections with the Distribution System

B.1 General Requirements

Any Facility desiring to interconnect with the Company's Distribution System or modify an existing interconnection must meet minimum specifications, where applicable, as set forth in the following documents and standards. Additional requirements, including clarification of the specifications contained in these documents are outlined in Section _ (*Process requirement for assigning Facilities under Simplified, Expedited or Standard Review paths*) and Section B.3.3.

1. Institute of Electrical and Electronic Engineers (IEEE) P1547 Draft Standard for Distributed Resources Interconnected with Electric Power Systems.

2. Underwriters Laboratories Inc. Standard UL 1741, November 1, 2002 "Inverters, Converters and Charge Controllers for Use in Independent Power Systems

3. IEEE Standard 929-2000, "IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems".

The specifications and requirements listed herein are intended solely to mitigate possible adverse impacts caused by the Facility on the Company's equipment and personnel and on other customers of the Company. They are not intended to address protection of the Facility itself or its internal load. It is the responsibility of the Facility to comply with the requirements of all appropriate standards, codes, statutes and authorities to protect itself and its loads.

The Company shall not be responsible for the protection of the Facility's facilities. The Facility shall be responsible for protection of its system against possible damage resulting from parallel operation with the Company. If requested by the Interconnecting Customer, the Company will provide system protection information for the line terminal(s) directly related to the interconnection. This protection information contained herein is provided exclusively for use by the Interconnecting Customer to evaluate protection of its Facility during parallel operation.

At its sole discretion, the Company may consider approving alternatives that satisfy the intent of the requirements contained in this Appendix.

B.2 Facility Classification

To determine the protection requirements for a given Facility, the following Groups have been established:

Group	Type of Interconnection
1	Facilities Qualified for Simplified Interconnection
2	All Facilities Not Qualified for Simplified Interconnection

B.3 Protection Requirements

I. Group 1 Facilities

a. The inverter-based Facility shall be considered *qualified* if it meets requirements set for in Section 3, *"Narrative Process for Distributed Generation Interconnection in Massachusetts."* (*Box 3 of Figure 1 schematic*)

b. **External Disconnect Switch**: For qualified inverters, a Company **may** require an external disconnect switch (or comparable device by mutual agreement of the Parties) at the point of common coupling with the Company or at another mutually agreeable point that is accessible to Company personnel at all times and that can be opened for isolation if the switch is required. The switch shall be gang operated, have a visible break when open, be rated to interrupt the maximum generator output and be capable of being locked open, tagged and grounded on the Company side by Company personnel. The visible break requirement can be met by opening the enclosure to observe the contact separation. The Company shall have the right to open this disconnect switch in accordance with the Tariff..

II. Group 2 Facilities

General Requirements

a. All Group 2 Generating Facilities must meet performance requirements set forth in relevant sections of the IEEE P1547 Draft Standard including:

4.1.1 Voltage Regulation

The DR shall not actively regulate the voltage at the PCC. The DR shall not cause the Area EPS service voltage at other Local EPS' to go outside the requirements of ANSI C84.1, Range A.

4.1.2 Integration with Area EPS Grounding

The grounding scheme of the DR interconnection shall not cause overvoltages that exceed the rating of the equipment connected to the Area EPS and shall not disrupt the coordination of the ground fault protection of the Area EPS.

4.1.3 Synchronization

The DR unit shall parallel with the Area EPS without causing a voltage fluctuation at the PCC greater than ± 5% of the prevailing voltage level of the Area EPS at the PCC, and meet the flicker requirements of clause 4.3.2.

4.1.8.2 Surge Withstand Performance

The interconnection system shall have the capability to withstand voltage and current surges in accordance with the environments defined in IEEE/ANSI C62.41.2 or IEEE C37.90.1 as applicable.

4.2 Response to Area EPS Abnormal Conditions[6]

Abnormal conditions can arise on the Area EPS that require a response from the connected DR. This response contributes to the safety of utility maintenance personnel and the general public, as well as the avoidance of damage to connected equipment, including the DR. All voltage and frequency parameters specified in these sub-clauses shall be met at the PCC, unless otherwise stated.

4.2.1 Area EPS Faults

The DR unit shall cease to energize the Area EPS for faults on the Area EPS circuit to which it is connected.

4.2.2 Area EPS Reclosing Coordination

The DR shall cease to energize the Area EPS circuit to which it is connected prior to reclosure by the Area EPS.

4.2.3 Voltage

The protection functions of the interconnection system shall detect the effective (RMS) or fundamental frequency value of each phase-to-phase voltage, except where the transformer connecting the Local EPS to the Area EPS is a grounded wye-wye configuration, or single phase installations, the phase to neutral voltage shall be detected. When any voltage is in a range given below (Table 1), the DR shall cease to energize the Area EPS within the clearing time as indicated. Clearing time is the time between the start of the abnormal condition and the DR ceasing to energize the Area EPS. For DR less than or equal to 30 kW in peak capacity, the voltage set points and clearing times shall be either fixed or field adjustable. For DR greater than 30 kW the voltage set points shall be field adjustable.

The voltages shall be detected at either the PCC or the point of DR connection when any of the following conditions exist:

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[6] *The isolation of a portion of the Area EPS, presenting the potential for an unintended DR island, is a special concern and is addressed in clause 4.4.1. Setting adjustments may only be made as approved by the authority who has jurisdiction over the DR interconnection.*

(a) The aggregate capacity of DR systems connected to a single PCC is less than or equal to 30 kW, (b) the interconnection equipment is certified to pass a non-islanding test for the system to which it is to be connected, (c) the aggregate DR capacity is less than 50% of the total Local EPS minimum annual integrated electrical demand for a 15 minute time period, and export of real or reactive power by the DR to the Area EPS is not permitted.

Table 1. Interconnection System Response to Abnormal Voltages	
Voltage Range (% of base voltage[a])	Clearing Time [b] (s)
V< 50	0.16
50 ≤V<88	2
110<V<120	1
V •120	0.16
Notes. (a) Base voltages are the nominal system voltages stated in ANSI C84.1 Table 1. (b) DR ≤ 30kW, Maximum Clearing Times; DR > 30kW, Default Clearing Times	

4.2.4 Frequency

When the system frequency is in a range given below (Table 2), the DR shall cease to energize the Area EPS within the clearing time as indicated. Clearing time is the time between the start of the abnormal condition and the DR ceasing to energize the Area EPS. For DR less than or equal to 30 kW in peak capacity, the frequency set points and clearing times shall be either fixed or field adjustable. For DR greater than 30 kW the frequency set points shall be field adjustable. Adjustable underfrequency trip settings shall be coordinated with Area EPS operations.

Table 2. Interconnection System Response to Abnormal Frequencies		
DR SIZE	**Frequency Range (Hz)**	**Clearing Time [a] (s)**
•30 kW	> 60.5	0.16
	<59.3	0.16
>30 kW	>60.5	0.16
	< {59.8 - 57.0} (adjustable setpoint)	Adjustable 0.16 to 300
	<57.0	0.16
Note. (a) DR •30 kW, Maximum Clearing Times; DR > 30 kW, Default Clearing Times		

4.2.5 Loss of Synchronism

Loss of synchronism protection is not required except as necessary to meet clause 4.3.2.

4.2.6 Reconnection To Area EPS

After an Area EPS disturbance, no DR reconnection shall take place until the Area EPS voltage is within Range B of ANSI C84.1 Table 1, and frequency range of 59.3Hz to 60.5Hz.

The DR interconnection system shall include an adjustable delay (or a fixed delay of five minutes) that may delay reconnection for up to five minutes after the Area EPS steady state voltage and frequency are restored to the ranges identified above.

4.3.2 Limitation of Flicker Induced by the DR

The DR shall not create objectionable flicker for other customers on the Area EPS.[7]

4.3.3 Harmonics

When the DR is serving balanced linear loads, harmonic current injection into the Area EPS at the PCC shall not exceed the limits stated below (Table 3). The harmonic current injections shall be exclusive of any harmonic currents due to harmonic voltage distortion present in the Area EPS without the DR connected.

Table 3. Maximum Harmonic Current Distortion in Percent of Current (a) (I)						
Individual Harmonic Order h (Odd Harmonics) (b)	*h <11*	*11•h < 17*	*17 •h < 23*	*23•h <35*	*35 •h*	*Total Demand Distortion (TDD)*
Percent (%)	*4.0*	*2.0*	*1.5*	*0.6*	*0.3*	*5.0*
(a) I = the greater of the Local EPS maximum load current integrated demand (15 or 30 min) without the DR unit, or the DR unit rated current capacity (transformed to the PCC when a transformer exists between the DR unit and the PCC). *(b) Even harmonics are limited to 25% of the odd harmonic limits above.*						

4.4.1 Unintentional Islanding

For an unintentional island in which the DR energizes a portion of the Area EPS through the PCC, the DR interconnection system shall detect the island and cease to energize the Area EPS within two seconds of the formation of an island.[8]

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[7] *Flicker is considered objectionable when it either causes a modulation of the light level of lamps sufficient to be irritating to humans, or causes equipment mis-operation. For guidance, refer to IEEE STD 519-1992 IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems; IEEE P1453 Draft Recommended Practice for Measurement and Limits of Voltage Flicker on AC Power Systems; International Electrotechnical Commission IEC/TR3 61000-3-7Assessment of Emission Limits for Fluctuating Loads in MV and HV Power Systems; IEC 61000-4-15 Flickermeter - Functional and Design Specifications,; and IEC 61400-21 IEC 61400-21, Wind Turbine Generator Systems - Part 21: Measurement and assessment of power quality characteristics of grid connected wind turbines - Ed. 1.0 (2000-12)*

[8] *Some examples by which this requirement may be met are:*
1. The DR aggregate capacity is less than one-third of the minimum load of the Local EPS.
2. The DR is certified to pass an applicable non-islanding test.

a. Non Export Power: If the parties mutually agree that non-export functionality will be part of the interconnection protection equipment then it will include one of the following: (1) a reverse power relay with mutually agreed upon delay intervals, or (2) a minimum power function with mutually agreed upon delay intervals, or (3) or other mutually agreeable approaches, for example, a comparison of nameplate rating versus certified minimum facility load.

b. The ISO-New England is responsible for assuring compliance with NPCC criteria. Under some interconnection of larger units, the NPCC criteria may additionally require:

NPCC Protective Relaying Requirements: The Company may require the Facility to be equipped with two independent, redundant relaying systems in accordance with NPCC criteria, where applicable, for the protection of the bulk power system if the interconnection is to the bulk power system or if it is determined that delayed clearing of faults within the Facility adversely affects the bulk power system.

NPCC Requirements: During system conditions where local area load exceeds system generation, NPCC Emergency Operation Criteria requires a program of phased automatic under frequency load shedding of up to 25% of area load to assist in arresting frequency decay and to minimize the possibility of system collapse. Depending on the point of connection of the Facility to the Company's system and in conformance with the NPCC Emergency Operating Criteria, the Facility may be required to remain connected to the system during the frequency decline to allow the objectives of the automatic load shedding program to be achieved, or to otherwise provide compensatory load reduction, equivalent to the Facility's generation lost to the system, if the Interconnecting Customer elects to disconnect the Facility at a higher under frequency set point.

c. **Disconnect Switch:** The Facility shall provide a disconnect switch (or comparable device mutually agreed upon by the parties) at the point of Generating Facility interconnection that can be opened for isolation. The switch shall be in a location easily accessible to Company personnel at all times. The switch shall be gang operated, have a visible break when open, be rated to interrupt the maximum generator output and be capable of being locked open, tagged and grounded on the Company side by Company personnel. The visible break requirement can be met by opening the enclosure to observe the contact separation. The Company shall exercise such right in accordance with the Facility Disconnection Section of the Tariff.

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3. The DR installation contains reverse or minimum power flow protection, sensed between the Point of DR Connection and the PCC, which will disconnect or isolate the DR if power flow from the Area EPS to the Local EPS reverses or falls below a set threshold.
4. The DR contains other non-islanding means such as a) forced frequency or voltage shifting, b) transfer trip, or c) governor and excitation controls that maintain constant power and constant power factor.

d. **Transfer Tripping:** A direct transfer tripping system, if one is required by either the Interconnecting Customer or by the Company, shall use equipment generally accepted for use by the Company and shall, at the option of the Company, use dual channels.

Requirements for Induction and Synchronous Generator Facilities:

a. **Interconnection Interrupting Device:** An Interconnection Interrupting Device such as a circuit breaker shall be installed to isolate the Generating Facility from the Company's system. If there is more than one Interrupting Device, this requirement applies to each one individually. The Interconnection Interrupting Device must be capable of interrupting the current produced when the Facility is connected out of phase with the Company's system, consistent with Section 4.1.8.3 of the IEEE P1547 Draft Standard which states, "*The interconnection system paralleling-device shall be capable of withstanding 220% of the interconnection system rated voltage*."

b. **Synchronizing Devices:** The Interconnecting Customer shall designate one or more Synchronizing Devices such as motorized breakers, contactor/breaker combinations, or a fused contactor (if mutually agreeable) to be used to connect the Facility's generator to the Company's system. This Synchronizing Device could be a device other than the Interconnection Interrupting Device. The Synchronizing Device must be capable of interrupting the current produced when the Facility is connected out of phase with the Company's system, consistent with Section 4.1.8.3 of the IEEE P1547 Draft Standard which states, "*The interconnection system paralleling-device shall be capable of withstanding 220% of the interconnection system rated voltage*."

c. **Transformers:** The Company reserves the right to specify the winding connections for the transformer between the Company's voltage and the Facility's voltage ("Step Up Transformer") as well as whether it is to be grounded or ungrounded at the Company's voltage. In the event that the transformer winding connection is grounded-wye/grounded-wye the Company reserves the right to specify whether the generator stator is to be grounded or not grounded. The Interconnecting Customer shall be responsible for procuring equipment with a level of insulation and fault withstand capability compatible with the specified grounding method.

d. **Voltage relays:** Voltage relays shall be frequency compensated to provide a uniform response in the range of 40 to 70Hz.

e. **Protective Relaying Redundancy:** For induction generators greater than 1/15 of on-site minimum verifiable load that is not equipped with on-site capacitors or that is greater than 200 kW, and for all synchronous generators, protective relays utilized by the Facility shall be sufficiently redundant and functionally separate so as to provide adequate protection, consistent with Company practices and standards, upon the failure of any one component.

f. **Protective Relay Hard-Wire Requirement:** Unless authorized otherwise by the Company, protective relays must be hardwired to the device they are tripping. Further,

interposing computer or programmable logic controller or the like is not permitted in the trip chain between the relay and the device being tripped.

g. **Protective Relay Supply:** Where protective relays are required by this Protection Policy, their control circuits shall be DC powered from a battery/charger system or a UPS. Solid-state relays shall be self-powered, or DC powered from a battery/charger system or a UPS. If the Facility uses a Company-acceptable non-latching interconnection contactor, AC powered relaying shall be allowed provided the relay and its method of application is fail safe, meaning that if the relay fails or if the voltage and/or frequency of its AC power source deviate from the relay's design requirements for power, the relay or a separate fail-safe power monitoring relay acceptable to the Company will immediately trip the generator by opening the coil circuit of the Interconnection Contactor.

h. **Current Transformers:** CT ratios and accuracy classes shall be chosen such that secondary current is less than 100 amperes and transformation errors are consistent with Company practices.

i. **Voltage Transformers and Connections:** The Facility shall be equipped with a direct voltage connection or a voltage transformer (VT), connected to the Company side of the Interrupting Device. The voltage from this VT shall be used in an interlock scheme, if required by the Company. For three phase applications, a VT for each phase is required. All three phases must be sensed either by three individual relays or by one relay that contains three elements. If the voltage on any of the three phases is outside the bounds specified by the Company the unit shall be tripped. If the Facility's step up transformer is ungrounded at the Company voltage, this VT shall be a single three-phase device or three single-phase devices connected from each phase to ground on the Company's side of the Facility's step up transformer, rated for phase-to-phase voltage and provided with two secondary windings. One winding shall be connected in open delta, have a loading resistor to prevent ferroresonance, and be used for the relay specified in these requirements.

Additional Requirements for Induction Generator Facilities

a. Self-Excitation: A Facility using induction generators connected in the vicinity of capacitance sufficient to self-excite the generator(s) shall meet the requirements for synchronous machines. The capacitors that enable self-excitation may actually be external to the Facility. The Company will not restrict its existing or future application of capacitors on its lines nor restrict their use by other customers of the Company to accommodate a Facility with induction machines. If self-excitation becomes possible due to the installation of or presence of capacitance, the protection requirements of the Generating Facility may need to be reviewed and revised, if applicable.

The Facility may be required to install capacitors to limit the adverse effects of drawing reactive power from the system for excitation of the generator. Capacitors for supply of reactive power at or near the induction generator with a kVAR rating greater than 30% of the generator's kW rating may cause the generator to become self-excited. (If self-

excitation can occur, the Facility shall be required to provide protection as specified in synchronous machines requirements.)

Additional Requirements for Synchronous Generator Facilities

a. **Ungrounded Transformers:** If the Facility's step up transformer connection is ungrounded, the Facility shall be equipped with a zero sequence overvoltage relay fed from the open delta of the three phase VT specified in the Voltage Transformers and Connections section above.

b. **High-Speed Protection:** The Facility may be required to use high-speed protection if time-delayed protection would result in degradation in the existing sensitivity or speed of the protection systems on the Company's lines.

c. **Breaker Failure Protection:** The Facility may be required to be equipped to provide local breaker failure protection which may include direct transfer tripping to the Company's line terminal(s) in order to detect and clear faults within the Facility that cannot be detected by the Company's back-up protection.

d. **Communications Channels:** The Interconnecting Customer is responsible for procuring any communications channels necessary between the Facility and the Company's stations and for providing protection from transients and overvoltages at all ends of these communication channels. The Interconnecting Customer will also bear the ongoing cost to lease these communication channels. Examples include, but are not limited to, connection to a line using high-speed protection, transfer tripping, Generators located in areas with low fault currents, or back up for Generator breaker failure.

B.3.4 Protection System Testing and Maintenance

The Company shall have the right to witness the commissioning testing as defined in IEEE P1547 Draft Standard Section 5.4 at the completion of construction and to receive a copy of all test data. The Facility shall be equipped with whatever equipment is required to perform this test.

Testing typically includes, but is not limited to:

- CT and CT circuit polarity, ratio, insulation, excitation, continuity and burden tests,
- VT and VT circuit polarity, ratio, insulation and continuity tests,
- Relay pick-up and time delay tests,
- Functional breaker trip tests from protective relays,
- Relay in-service test to check for proper phase rotation and magnitudes of applied currents and voltages,
- Breaker closing interlock tests, and
- Paralleling and disconnection operation.

Prior to final approval by The Company or anytime thereafter, the Company reserves the right to test the generator relaying and control related to the protection of the Company's system.

The Customer has the full responsibility for the proper periodic maintenance of its generating equipment and its associated control, protective equipment and interrupting devices.

The Customer is responsible for the periodic maintenance of those relays, interrupting devices, control schemes, and batteries that involve the protection of the Company's system. A periodic maintenance program, mutually agreeable to both The Company and to The Customer is to be established in each case. The Company shall have the right to monitor the periodic maintenance performed.

For relays installed in accordance with the NPCC Criteria for the Protection of the Bulk Power System, maintenance intervals shall be in accordance with such criteria. The results of these tests shall be summarized by the Interconnecting Customer and reported in writing to the Company.

The Company reserves the right to install special test equipment as may be required to monitor the operation of the Facility and its control or for evaluating the quality of power produced by the Facility at a mutually agreed upon location.

Each routine check shall include both a calibration check and an actual trip of the circuit breaker or contactor from the device being tested. Visually setting a calibration dial, index or tap is not considered an adequate calibration check.

Inverters with field adjustable settings for their internal protective elements shall be periodically tested if those internal elements are being used by the Facility to satisfy the requirements of this Protection Policy.

B.5 Protection Requirements – Momentary Paralleling of Standby Generators

Protective relays to isolate the Facility for faults in the Company's system are not required if the paralleling operation is automatic and takes place for less than one-half of a second. An Interrupting Device with a half-second timer (30 cycles) is required as a fail-safe mechanism.

Parallel operation of the Facility with the Company’s system shall be prevented when the Company's line is dead or out of phase with the Facility.

The control scheme for automatic paralleling must be submitted by the Interconnecting Customer for review and acceptance by the Company prior to the Facility being allowed to interconnect with the Company’s system.

B.6 Protection System Changes

The Interconnecting Customer must provide the Company with reasonable advance notice of any proposed changes to be made to the protective relay system, relay settings, operating procedures or equipment that affect the interconnection. The Company will

determine if such proposed changes require re-acceptance of the interconnection per the requirements of this Protection Policy.

In the future, should the Company implement changes to the system to which the Facility is interconnected, the Interconnecting Customer will be responsible at its own expense for identifying and incorporating any necessary changes to its protection system. These changes to the Facility's protection system are subject to review and approval by the Company.

Appendix C: Information Tracking Form (Illustrative Example)

			Name	Installation A		Installation B		Installation C		Installation D		Installation E	
Simplified			Address	26 Main St., Westboro, MA		22 Main St., Westboro, MA		24 Main St., Westboro, MA		28 Main St., Westboro, MA		26 Main St., Westboro, MA	
			ID number	M-1		M-2		M-3		M-4			
			size (kW)	75		750		150		10		75	
			fuel source	gas		gas		gas		gas		gas	
			DG type [1]	1		2		1		5			
			prime mover	microturbine									
			Does project require air quality permit?	y									
				Date	Costs	Date	Costs	Date	Costs	Date	Costs	Date	Costs
			Application filed	1/16/2003	$300	1/16/2003	$2,250	1/16/2003	$450	1/16/2003	$0	1/16/2003	$300
			Receipt of Application noted	1/16/2003		1/16/2003		1/16/2003		1/16/2003		1/16/2003	
			Status of Completeness of application	1/21/2003		1/21/2003		1/21/2003		1/21/2003		1/21/2003	
			Is application complete?	Y		Y		Y		Y		Y	
			Type of Review [2]	2		3		6		1			
			Utility Service type [3]	1									
			screen 1	y									
			screen 2	y									
			screen 3	y									
			screen 4	n									
			screen 5	y									
			screen 6	y									
			screen 7	y									
			screen 8	y									
			Initial Review completed	1/25/2003									
			Supplemental review, if necessary, agreed to by customer	1/25/2003									
			Supplemental review, if necessary, completed	1/26/2003	$1,250								$1,250
Simplified			Agreement										
			Witness test scheduled										
		Standard Review	Standard review completed (provide impact study estimate)										
			Impact Study completed				$4,500						$4,500
			Facilities Study completed				$4,500						$4,500
			SR Agreement completed										
			SR Witness test scheduled										
Man-hrs required (professional)			For Initial Review										
			For Supplemental Review										
			For Impact Study										
			For Facilities Study										
			For Agreement										
			For Witness test										
Date system on-line													
System modifications required?													
Total business days and costs for review													
Notes: Did project fail any screens? What was done in supplemental review? Cost of any system modifications? Reference where information is stored. Did project go to ADR?													

1) DG type: 1 - induction; 2 - synchronous; 3 - inverter
2) Type of review: 1 - Simplified; 2 - Expedited; 3 - Standard Review
3) Utility service type: 1 - radial; 2 - spot network; 3 - area network
4) Prime mover: 1 - microturbine, engine set, turbine, fuel cell, solar, wind, BPT

Appendix D: Draft Outline of Model Tariff

This draft outline is a work in progress. The DG Collaborative anticipates that the final model tariff will include these items. The final model tariff may include additional or different terms. In addition, detail in some areas does not imply exhaustive treatment. The DG Collaborative anticipates submitting the final model tariff to DTE by March 31, 2003.

1. Introduction:

    - Applicability
    - Definitions: All Capitalized Terms will have definitions (could be in an attachment)
    - Statement of enabling documents, reference that entire agreement is tariff and contract (see attachments)
    - Basic Understandings: Background explanation of the tariff
    - Statement that tariff does not cover electric service
    - Statement that tariff does not cover use of distribution system to export power

2. Responsibilities of parties

    - Summary description of the obligations of the parties to operate according to good utility practice and in compliance with all applicable laws and regulations
    - Authorization to Interconnect

3. Interconnection process overview: This will include Collaborative products covering:

    - Application
    - Methodologies
    - Timelines, including computation of time, stopping of clock, consequences of delay, etc.
    - Costs
    - Equipment Certification

4. Interconnection Requirements: Insert Exhibit B of DG Collaborative Report

    - Technical Information (Engineering and Design Considerations)
    - Technical Requirements (includes operating and design requirements)
    - Testing
    - Maintenance

5. General Operating Requirements

    - Utility access to the DG facility under emergency and standard operating conditions
    - Procedures for ensuring compliance with technical requirements
    - Performance Exceptions (utility rights re: power quality, complaint resolution, outages, synchronization, etc.)

- Disconnection and Reconnection: technical aspects, temporary and/or permanent

6. Metering, monitoring and communication

   - Net Metering
   - Bi-directional Metering (NEPOOL requirements, etc.)
   - Monitoring
   - Notification and Communication

7. Cost Responsibilities

   - General statement regarding costs
   - Specific allocation re: who pays for what
   - Application, review and study costs
   - Facility upgrade costs
   - O&M to be addressed in Phase 2 of the DTE proceeding (and inserted at that point)
   - Other

8. Dispute Resolution (include Dispute Resolution system developed by Collaborative)

9. Treatment of Confidential Information:

   - Groundrules
   - Address in application, tariff and contract

10. Insurance (general statement –specifics in contract, as outlined below)

11. Exhibits

    A. Service Agreement for all Expedited and Standard Projects

       a. Identification of Parties
       b. Basic Understandings
       c. Term and Termination
       d. Billing and Payment
       e. Security and Creditworthiness
       f. Milestones, e.g. energize within x months
       g. Disconnections for breach of contract, technical requirements re: adverse operating conditions, maintenance, outages, emergencies
       h. Right to Inspect, including operating records
       i. Assignment
       j. Statement of Confidentiality/Non-disclosure of commercial information
       k. Insurance (specific requirements)
       l. Indemnification
       m. Limitation of Liability
       n. Amendments and Modifications
       o. Compliance with all applicable laws and regulations
       p. Force Majeure

q. Legal Notice
r. Normal Communication (day-to-day)
s. Interplay between Contract and Tariff re: entire agreement provisions
t. Interpretation; singular, plural, etc.
u. Supercedence
v. No Third Party Beneficiaries
w. Governing Law
x. Non-waiver
y. Counterparts
z. No Partnership
aa. Survival of Obligations
bb. Third Party Responsibilities/three party agreements
cc. Dispute Resolution – reference system developed by Collaborative
dd. Attachment 1: Description of Facilities, including demarcation of point of interconnection
ee. Attachment 2: System Upgrades
ff. Attachment 3: Costs of Upgrades
gg. Attachment 4: Special Operating Requirements, if any

B. Third Party Owner Agreement
C. Application (Appendix A in DG Collaborative Report)
D. Separate Application/Contract for Simplified Interconnections (see note below)
E. Supplemental Review Costs Agreement
F. Impact Study Agreement
G. Facility Study Agreement

12. Other Provisions:

A. Review tariff and contract experience as part of on-going Collaborative (note this is Section 6 of DG Collaborative Report)
   a. Contract mechanism for addressing third party developer/customer projects, including the following provisions, plus others:
   b. Access
   c. Indemnification
   d. Consequences
   e. Other

NOTE: PROPOSED CONCEPT FOR SIMPLIFIED CONTRACT

The simplified interconnection process will also be governed by the tariff. The application form will include relevant commercial terms and the interconnecting customer will not sign a separate service agreement. The DG Collaborative is developing the combined application/contract with commercial terms and will submit them with the final tariff.

Appendix E: Collaborative Membership and Participation [9]

Membership

	Organization	Representative	Alternate
DG Providers (6 seats)	Aegis Energy Services	Spiro Vardakas	
	Solar Energy Business Assoc. NE	Steve Cowell	Ed Kern
	The E-Cubed Company, LLC	Peter Chamberlain	Ruben Brown
	Ingersoll-Rand	Jim Watts	
	NAESCO	Don Gilligan	
	Northeast CHP Initiative	Sean Casten	
	Northeast Commerce Association	Larry Plitch	
	Real Energy	Roger Freeman	
	United Technologies Corp.	Herb Healy	Heather Hunt
Gov't/ Quasi Government (4 seats)	MA Division of Energy Resources	Gerry Bingham	David Rand
	Massachusetts Technology Collaborative	Sam Nutter	Judy Silvia
	Attorney General's Office	Joseph Rogers	Judith Laster
	Cape Light Compact	Margaret Downey	
Customers (3 seats)	Associated Industries of Massachusetts	Angie O'Connor	
	for Solutia and MeadWestVac Co.	Andy Newman	
	Wyeth BioPharmaceutical	Susan Richter	
Utilities (5 seats)	Fitchburg Gas & Electric (Unitil)	John Bonazoli	Justin Eisfeller
	ISO-New England	Henry Yoshimura	Carolyn O'Connor
	NSTAR Electric	Larry Gelbien	Dave Dishaw
	W. Mass Elect. Co (Northeast Utilities)	Doug Clarke	Rich Towsley
	MECo (National Grid)	Tim Roughan	John Bzura
Pub.Int. Groups (2 seats)	UCS, MASSPIRG, CLF et al.	Deborah Donovan	Frank Gorke
	Mass Energy Consumers Alliance	Larry Chretien	Leslie Grossman

[9] This was the original Collaborative membership MeadWestCo withdrew from the Collaborative at the end of Phase I. Both the Attorney General and NAESCo were members but did not attend any meetings.

Participation by Representatives, Alternates, and Others

Organization	Name	11/4	11/15	11/20	12/6	12/11	12/13	1/10	1/16	1/29	2/13	2/14	2/26
DG PROVIDERS													
Aegis Energy Services	Spiro Vardakas	X	X	X	X	X		X		X	X	X	X
Solar Energy Business Assoc. NE	Steve Cowell	X	X		X	X	X	X		X	X*	X	X
Solar Energy Business Assoc. NE (alternate)	Ed Kern	X	X	X	X	X	X	X	X				
Solar Energy Business Assoc. NE (alternate)	Paul Lyons							X					
The E-Cubed Company, LLC	Peter Chamberlain	X	X	X	X	X	X*	X	X	X	X	X	X
The E-Cubed Company, LLC (alternate)	Ruben Brown	X	X	X	X	X		X					
Ingersoll-Rand	Jim Watts	X	X	X	X	X	X	X	X	X	X	X	X
Ingersoll-Rand (alternate)	Jim Avery	X						X					
Ingersoll-Rand (alternate)	Tim O'Connell							X					
NAESCO	Don Gilligan												
Northeast CHP Initiative/Turbosteam	Sean Casten	X	X	X	X			X	X	X		X	X
Turbosteam	Tim Walsh							X					
Northeast Commerce Association	Larry Plitch	X	X	X									
Northeast Commerce Association (alternate)	Tobey Winters	X	X										
Real Energy	Roger Freeman	X	X	X	X	X	X	X	X		X	X	X
Real Energy (alternate)	Tim Daniels							X	X	X	X	X	X
United Technologies Corp.	Herb Healy	X		X	X	X	X	X	X	X	X	X	X
United Technologies Corp. (alternate)	Heather Hunt		X										
Keyspan	Pat Crowe	X											
Keyspan	Joe Niemiec		X		X		X					X	X
Keyspan	Chuck Berry		X		X	X	X	X					
Keyspan	Rich Johnson			X					X	X			
Plug Power	Lisa Potter		X									X	
Plug Power	Rudy Stegemoeller			X									
Trigen Energy	Dave Doucette		X	X		X						X	X
GOVERNMENT/QUASI GOVERNMENT		**11/4**	**11/15**	**11/20**	**12/6**	**12/11**	**12/13**	**1/10**	**1/16**	**1/29**	**2/13**	**2/14**	**2/26**
MA Div. of Energy Resources	Gerry Bingham	X	X	X				X	X	X	X	X	X
MA Div. of Energy Resources (alternate)	David Rand	X	X	X	X	X	X						
Mass Technology Collaborative	Sam Nutter	X	X	X	X	X	X	X	X	X	X	X	X
Mass Technology Collaborative. (alternate)	Judy Silvia	X		X		X							
Mass Technology Collaborative. (alternate)	Raphael Herz	X	X	X	X	X	X	X					
Mass Technology Collaborative (alternate)	Fran Cummings							X	X	X		X	X
Mass Technology Collaborative (alternate)	Quincy Vale								X	X			
Attorney General's office	Joseph Rogers												
Attorney General's office	Judith Laster												
Attorney General's office	Patricia Kelley												
Cape Light Compact	Margaret Downey	X											
Cape Light Compact	Kitt Johnson		X	X			X	X			X	X	X
Dep't of Telecom. & Energy	Paul Afonso	X											
CONSUMERS		**11/4**	**11/15**	**11/20**	**12/6**	**12/11**	**12/13**	**1/10**	**1/16**	**1/29**	**2/13**	**2/14**	**2/26**
Associated Industries of Massachusetts	Angie O'Connor		X	X	X	X						X	
Solutia and MeadWestVac Co.	Andy Newman	X	X	X			X						
Wyeth	Susan Richter	X	X	X		X			X	X			

UTILITIES		**11/4**	**11/15**	**11/20**	**12/6**	**12/11**	**12/13**	**1/10**	**1/16**	**1/29**	**2/13**	**2/14**	**2/26**
Unitil/Fitchburg Gas & Electric	John Bonazoli		X	X	X	X	X	X	X		X	X	X
Unitil/Fitchburg Gas & Electric (alternate)	Justin Eisfeller		X	X	X	X	X			X		X	
ISO-New England	Henry Yoshimura	X	X	X		X	X						
ISO-New England (alternate)	Carolyn O'Connor	X		X						X			
ISO-New England (2nd Alternate	Eric Krathwohl			X	X								
NSTAR Electric	Larry Gelbien	X	X	X		X		X	X	X		X	X
NSTAR Electric (alternate)	Dave Dishaw	X	X	X	X	X	X	X	X	X	X	X	X
NSTAR Electric (alternate)	Mary Grover							X	X	X			
NSTAR Electric (alternate)	Dan Butterfield	X	X	X	X	X	X	X	X	X	X	X	X
WMECO (NU)	Doug Clarke	X	X	X	X	X	X	X	X	X	X	X	X
WMECO (NU) (alternate)	Mary Duggan							X					
WMECO (NU) (alternate)	Cindy Janke							X	X	X	X	X	X
WMECO (NU) (alternate)	Steve Klionsky							X				X	X
WMECO (NU) (alternate)	Steve Gibelli									X			
WMECO (NU) (alternate)	Rich Towsley	X	X			X							
WMECO (NU) (alternate)	Leo Rancourt	X	X	X				X	X	X			X
MECo/Nantucket (National Grid)	Tim Roughan	X	X	X	X	X	X	X	X	X	X	X	X
MECo/Nantucket (National Grid) (alternate)	John Bzura	X	X	X	X	X	X	X	X	X	X	X	X
MECo/Nantucket (National Grid) (alternate)	Amy Rabinowitz							X		X		X	
MECo/Nantucket (National Grid) (alternate)	Peter Zschokke							X					
MECo/Nantucket (National Grid) (alternate)	Judy Lee											X	
PUBLIC INTEREST GROUPS		**11/4**	**11/15**	**11/20**	**12/6**	**12/11**	**12/13**	**1/10**	**1/16**	**1/29**	**2/13**	**2/14**	**2/26**
UCS, MassPIRG, and CLF	Deborah Donovan		X					X		X	X		X
UCS, MassPIRG, and CLF	Frank Gorke				X								
UCS, MassPIRG, and CLF	Seth Kaplan		X		X	X							
Mass Energy Consumers Alliance	Larry Chretien		X		X		X	X					X
Mass Energy Consumers Alliance	Leslie Grossman	X		X	X	X						X	
COLLABORATIVE TEAM		**11/4**	**11/15**	**11/20**	**12/6**	**12/11**	**12/13**	**1/10**	**1/16**	**1/29**	**2/13**	**2/14**	**2/26**
Raab Associates	Jonathan Raab	X	X	X	X	X	X	X	X	X	X	X	X
Raab Associates	Joel Fetter	X	X	X	X	X	X	X	X	X	X	X	X
Raab Associates	Colin Rule	X	X	X	X	X	X	X	X				
Facilitation Consultant	Suzanne Orenstien	X	X	X	X	X	X	X	X	X	X	X	X
Navigant Consulting	Stan Blazewicz	X		X	X	X	X	X	X	X	X	X	X
Navigant Consulting	Eugene Shlatz	X	X	X	X			X			X	X	X
OTHER		**11/4**	**11/15**	**11/20**	**12/6**	**12/11**	**12/13**	**1/10**	**1/16**	**1/29**	**2/13**	**2/14**	**2/26**
Unaffiliated	Bill Feero							X					X

Appendix F: Alternative Timeframe Proposal and Rationale

RealEnergy appreciates the efforts made by all stakeholders to establish simplified uniform interconnection standards for Massachusetts and support the report of the DG Collaborative with one exception. RealEnergy believes that the majority proposed timelines are unreasonable and, if accepted, will constitute a continuing barrier to the development of distributed generation in Massachusetts.[10] While RealEnergy agrees with the principle of establishing interim timelines and reducing the timelines as experience is gained, we cannot agree with the proposed starting point for the interim timelines. Accordingly, RealEnergy respectfully dissents from the proposal of the majority and offers a counter proposal below.[11] If the DTE does not accept RealEnergy's proposal for the establishment of interim timelines, we respectfully request that the timelines become mandatory maximum timelines for implementation at the point of the first annual review.

Table 1: Time Frames[12]

Criteria for Process Classification	**Based on Evaluation of Technical Screens**		**Applicant Option**
Review Process	Simplified	Expedited	Standard Review
Eligible Facilities	Certified Inverter ≤ 10 kW	Qualified DG	Any DG
Acknowledge receipt of Application	(3 days)	(3 days)	(3 days)
Review Application for completeness	10 days	10	10
Complete Review of all screens	10 days	15/30	N/A
Total Maximum Days	15 days	25/40[13]	65/80[14] days
Notice/ Witness Test	< 1 day with 10 day notice or by mutual agreement	1-2 days with 10 day notice or by mutual agreement	By mutual agreement

[10] The interconnection process timelines agreed to by the majority are substantially in excess of both (1) timelines for interconnection in existing Massachusetts regulations applying to Qualifying Facilities and On-Site Generating Facilities (See 220 CMR §8.04(6)) and (2) the interconnection process timelines that have been developed in other states and proposed in the FERC ANOPR process.

[11] Simply put, RealEnergy believes that the current structure set forth in 220 CMR §8.04(6) establishes a preferable basis for a standard, whereby a more reasonable timeline is established but the Distribution Company retains the opportunity to seek extensions from the DTE for extenuating circumstances, such as disagreements over interconnection costs, or where extensive modifications are necessary.

[12] This Table is presented in a similar format as the majority proposal, however, the timelines in this proposal are for total business days and are not broken down by interim tasks. This will provide the utilities more flexibility for handling an interconnection application.

[13] Shorter time applies to Expedited w/o Supplemental Review, longer time applies to Expedited with Supplemental Review.

[14] Shorter time applies for Standard Review from beginning, longer time frame applies to standard review including initial expedited review process that was transferred to standard review.